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AN ASSESSMENT OF THE POTENTIAL FOR COAL-DERIVED SYNCRUDES IN CANADA

K. MORRIS MACRAE



**CANADIAN
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Preface

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The Institute is particularly indebted to Dr. N. Berkowitz, Professor of Fuel Science at the University of Alberta, who acted as an Advisor on this study, to the staff of the Oil Sands and Hydrocarbon Recovery Department of the Alberta Research Council, and to Dr. D. Quon of the University of Alberta. Thanks are also gratefully extended to many within industry and government who provided the data which permitted this study to be undertaken, and to those within the Institute who undertook the necessary graphics, word processing and editorial responsibilities.

All tables and graphs displayed in the report and the information contained therein, unless otherwise noted, are the responsibility of the Canadian Energy Research Institute.

The author is responsible solely for the views and conclusions expressed herein and for any errors or omissions that may exist.



EXECUTIVE SUMMARY

Introduction

According to a number of recent reports, Canada's reserves of conventional light crude oil are declining and, as a result, Canada could be importing substantial volumes of light crude oil in the 1990s. While Canada has made relatively successful strides in reducing its requirements of light oil, demand is expected to continue to grow. Indicative of such findings is the National Energy Board's (NEB) latest report on long-term energy supply and demand for Canada which concluded that productive capacity of conventional light crude oil is insufficient to replace production under a reasonable projection of long-term crude oil prices.

A projected growth in world oil demand, coupled with a forecast reduction in non-Opec supplies, heralds the prospect of higher real oil prices and the attendant costs of supply disruptions. Canada's forecast dependency on foreign supplies of crude oil translates to potentially significant, yet uncertain economic costs to the Canadian economy in the mid to long-term. A broadly based concern with Canada's projected level of dependency on foreign oil supplies and the potential for supply curtailment has sponsored a number of assessments of how best to ensure Canadian energy security. Many have cited the importance of funding additional research, development and demonstration of processes directed to increasing the domestic supply of oil, if Canada is to plan effectively and thereby enhance its future energy security.

Within the context of Canada's future energy demand and declining conventional crude oil production, this report examines recent advances in coal liquids technology and assesses the potential role of coal-derived synthetic fuels in Canada's evolving energy technology mix.

The conventional approach to assessing the economic viability of an energy technology is to carry out a standard economic process analysis. This report goes one step further. It imbeds the process economics of recent advances in coal liquids technology within the framework of a large-scale energy model, which takes into account all competing technologies over a long-term planning horizon. Thus, all

energy resources and technologies are compared in an internally consistent manner, under a common set of economic and market conditions. The model used in this study allocates, on an optimal basis, all the relevant Canadian energy resources--conventional and frontier crude oil, natural gas, bitumen, and coal--among the potentially available technologies and also over time.

Canada's Coal Resource Base

Canada's reserves of coal are immense and represent the largest proven reserves of any energy resource in Canada. Recent estimates indicate that domestic coal reserves contain 2.3 times the combined energy of all of Canada's other non-renewable energy resources.

Alberta's large reserves of subbituminous coals seem well-suited to recent technological improvements in coal/oil co-processing and direct coal liquefaction. While coal liquids facilities need not necessarily be located within Alberta, this province's huge endowment of low rank, inexpensive subbituminous coal and bitumen, together with natural gas for upgrading, offer Alberta a significant comparative advantage in the future large-scale production of synthetic fuels from coal.

While Canada's resource base indicates a significant potential for coal-derived synthetic fuels, the bulk of coal conversion research has concentrated on the bituminous and subbituminous coals of the United States. The characteristics of these U.S. coals differ somewhat from the subbituminous coals of Canada's Western Plains Region, which contain higher levels of oxygen and ash. Studies undertaken in Canada have all concluded that there is a great need to develop processes which are particularly suited to Canadian coals and siting opportunities. The difference in conversion characteristics between coals suggests that some "adoptive" research and demonstration will be required to economically convert Canadian low rank coals to synthetic fuels.

The Status of Coal Liquids Technology

Direct Liquefaction

There have been dramatic improvements made in coal liquefaction technology, especially in the last 5 years, and the impact of these

improvements has not been widely appreciated. The trend in process refinement in recent years has been towards milder operating conditions--lower pressure and temperature. Recent advances in the yield of distillate liquids without major penalties in hydrogen usage together with less severe operating conditions has meant a dramatic improvement in coal liquefaction economics.

In the mid to late 1970s, the economics of direct coal liquefaction indicated that the cost of crude oil liquids from coal would be in the range of \$60-\$80/bbl (\$U.S.). However, new designs and cost estimates based on recent improvements in technology show a 60 percent decrease in the cost of liquids from coal, down to an equivalent of \$35/bbl (\$U.S.) for crude oil. Moreover, additional improvements have been identified which could lower the cost of liquid fuels from coal to \$25/bbl (\$U.S.) or so over the next few years.

Recent assessments of technical advances in direct coal liquefaction have also confirmed that inexpensive subbituminous coals are excellent feedstocks for catalytic two-stage processing to synthetic liquid fuels. Subbituminous coals appear to require more severe processing conditions but achieve yields that are comparable to yields from bituminous coals. Improvement in solids removal technology (deashing) is expected to result in further and significant improvements in the economics of coal liquefaction.

Coal/Oil Co-Processing

Coal/oil co-processing is a relatively new coal liquefaction process which has gained considerable interest in the last decade. This process is an upgrading technology that involves the simultaneous conversion of coal and heavy oil or bitumen to synthetic crude oil.

Co-processing utilizes coal to increase distillate yields while eliminating the high recycle oil requirement of direct coal liquefaction. In the earlier direct coal liquefaction pilot plants, some 70 percent of the total liquid product stream was recycled in order to slurry the raw coal. In co-processing, the recycle solvent is replaced with fresh oil. Capital equipment is thereby more effectively used and the cost per unit of output is reduced. The fresh oil feed aids in the extraction of oil from coal and also acts to transfer hydrogen into the coal products while benefitting the conversion of the bitumen itself to distillate fuels.

Coal/oil co-processing has the potential for creating new domestic markets for inexpensive low rank subbituminous coals, natural gas and heavy oil/bitumen. Overall, coal/oil co-processing offers a number of advantages, especially where coal, heavy oil and/or bitumen and natural gas are centrally located and available at reasonable cost. The substantial endowment of centrally located bitumen and inexpensive subbituminous coal together with natural gas for hydrogen production in Alberta underscore the potential importance of coal/oil co-processing to future fuels development in Western Canada.

While these factors would generally support development in close proximity to the natural resource base, there are some instances where coal/oil co-processing also seems well-suited to consuming regions. Vacuum bottoms from conventional refinery operations can be combined with coal and natural gas at an adjacent co-processing plant to produce marketable boiler fuel products or can be upgraded to light fuel oils. The use of existing refinery capacity would mean that initial capital outlays to begin making synthetic fuels by coal/oil co-processing could be minimized and project risk would therefore be reduced relative to greenfield upgrading operations.

The use of coal via coal/oil co-processing upgrades bitumen to light oil and effectively results in an extension in the total production of light oil from Canada's limited heavy oil/bitumen production. Coal/oil co-processing would act to reduce concern over diluent supply and potential saturation of the U.S. export market for bitumen. As an alternative upgrading technology, it would also act to ameliorate concerns regarding Canada's growing dependence on foreign supplies of light crude oil. In summary, coal/oil co-processing could act to conserve natural gas condensates, displace imports of light crude oil, incorporate natural gas in the production of liquid fuels for export or domestic use, extend the production of crude oil from heavy oils, and create new domestic markets for Canadian coal.

By all indications, coal/oil co-processing appears a near-term application to the production of clean liquid fuels from coal. Current economics indicate that the cost of coal/oil co-processing is within reach of the production costs of integrated mined oil sands operations.

Indicative of interest in the potential importance of this technology are plans for construction and operation of a 12,000 b/d prototype commercial coal/oil co-processing plant in Ohio. In an effort to commercialize co-processing technology, the United States

Department of Energy has agreed to underwrite this project under the auspices of the U.S. Clean Coal Technology Program.

Within Alberta, Canadian Energy Developments Inc. has recently completed a detailed technical and financial analysis of a proposed coal/oil co-processing facility. The proposed plant was assumed to begin operations in 1992 and produce 20,900 b/d of syncrude quality crude comparable to that presently produced by Suncor and Syncrude. In 1987, Ontario agreed to fund a feasibility study of a prototype coal/oil co-processing plant. The study's objective is to evaluate the construction and operation of a demonstration plant in the Sarnia area to produce in the order of 12,500 b/d of light synthetic crude oil from a mixture of Ohio coal and either bitumen from Alberta or heavy refinery residues. In Nova Scotia, recent work has centered on the application of two-stage coal/oil co-processing for the upgrading of Cape Breton coals, employing the process technology to be used at the Ohio prototype commercial coal/oil co-processing plant.

Research Analysis and Key Results

While the assessments undertaken in the last several years point to a dramatic improvement in the economics of coal liquefaction, these studies have tended to evaluate coal liquefaction in isolation. An economic evaluation of the potential role of coal-derived synthetic fuels should, however, compare coal liquids processes with other competing technologies under the same economic and market conditions. In Canada, the cost of producing coal liquids must be competitive with the cost of production and delivery of frontier oil, synthetic crude oil from integrated mined oil sands plants, as well as in situ recovery and subsequent upgrading of heavy oil and bitumen. It is in this broader context that recent advances in coal liquids technologies are evaluated and assessed within this study.

The supply cost analysis, production and on-stream development scenarios presented in this paper for upgraders, mined oil sands plants and coal liquids facilities are based on a complete re-assessment of the potential costs of all of Canada's major energy supply options. The prospective sequencing and development of these supply options was appraised against a re-evaluation of Canadian demand for crude oil using the Canadian Energy Research Institute's CREED model, a regional end-use, energy demand model that accounts for interfuel substitution possibilities. This data, together with forecasts of primary energy prices, process technology costs and reserves information, was used

with a linear programming model developed by the Alberta Research Council to assess the prospective on-stream development of coal/oil co-processing and direct coal liquefaction relative to all other supply options.

A detailed evaluation undertaken by the MITRE Corporation in the United States of recent advances in direct coal liquefaction together with a study published by the Electric Power Research Institute on coal/oil co-processing formed the basis of our evaluation of state-of-the-art coal liquids technology. HRI's Catalytic Two-Stage Liquefaction process was chosen as indicative of a state-of-the-art direct liquefaction process, as it showed the best yields and lowest required product selling prices of the processes evaluated by MITRE. The HRI single-stage H-Coal process was also included in our assessment in order to evaluate and compare the two-stage liquefaction process with the earlier single-stage process configuration.

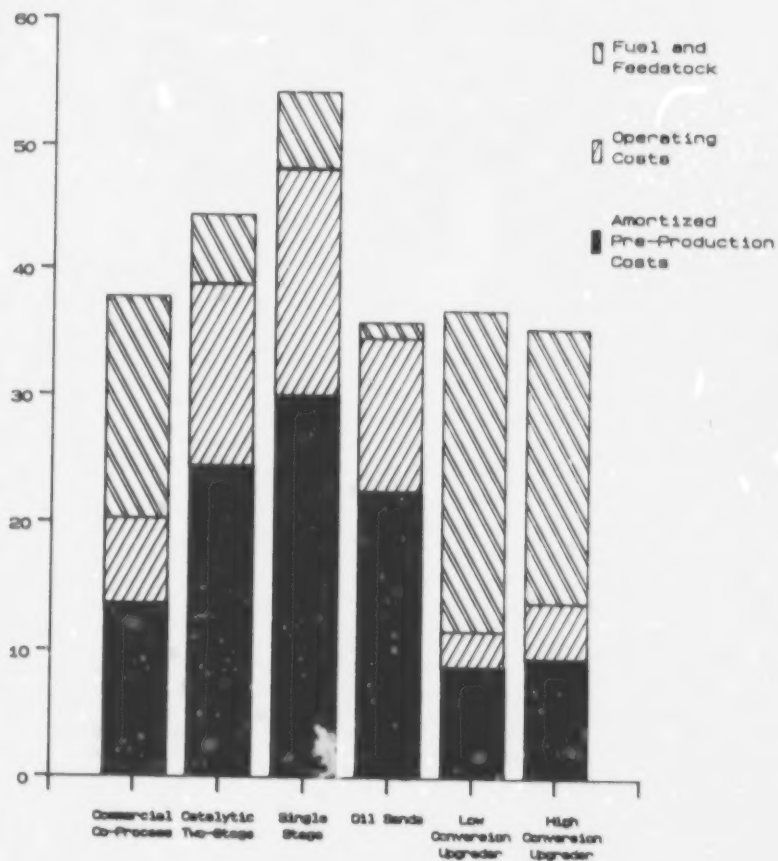
The derivation of supply costs for an Alberta location indicates that two-stage catalytic processing has indeed resulted in significant improvements in the cost of producing coal-derived liquid fuels. Including fuel and feedstock costs, the two-stage liquefaction process represents only 82 percent of the total supply cost of the single-stage direct liquefaction process. However, while comparative improvements in economics are evident, the total supply cost of the two-stage direct coal liquefaction process is still relatively high, over \$44/bbl (\$1986 Cdn.).

The economic evaluation of coal/oil co-processing presented in this study was based on the single-stage co-processing of coal and bitumen. Pending additional demonstration of the conversion properties of Alberta subbituminous coals, single-stage co-processing costs were believed to represent a reasonable estimate of the application of this technology within Alberta. In recognition, however, of the potential for reduced costs in use of the catalytic two-stage process configuration and of the likelihood of further improvements stemming from the U.S. prototype commercial co-processing demonstration plant, a 10 percent reduction in capital and operating costs was assumed for commercial coal/oil co-processing plants built in the latter 1990s.

The supply costs of the various options are graphically displayed in Figure 1 for 1995--a point in time when all process technologies are expected to be on a comparable footing in terms of the lead-time required for commercial demonstration. As presented in the figure, the supply costs of coal/oil co-processing stand at \$38/bbl

Figure 1
Supply Cost Comparison - 1995
(Reference Case)

1985 \$
 Cdn
 per bbl



SOURCE: Canadian Energy Research Institute.

compared to two-stage and single-stage direct liquefaction costs of \$44.38/bbl and \$54.32/bbl, respectively. A high conversion bitumen upgrader has a supply cost of \$35.46/bbl, followed by costs of oil sands plants and low conversion heavy oil/bitumen upgraders of \$36.05 and \$36.97/bbl, respectively (all prices in 1986 \$Cdn.).

Sensitivity analyses were undertaken to examine the effect of oil price uncertainty on the relative staging of coal liquids production. A low-price path trajectory results in a virtual standstill in new investment in synthetic crude oil capacity additions--low oil prices are insufficient to bring on new production in oil sands plants, upgraders or coal liquids plants. The net effect of low oil prices is a significant increase in Canadian demand for light crude oil and a marked reliance on imports. Alternatively, a forecast of high oil prices implies substantial growth in all synthetic crude oil options, particularly coal-derived synthetic fuels.

The sensitivity cases evaluated in this report all assume that a coal/oil co-processing demonstration (prototype commercial) plant would be in operation and producing in the order of 14,200 b/d of synthetic crude oil by 1997. This assumes that some initial site and coal-specific research occurs in the next few years. This assumption was predicated on the interest that coal/oil co-processing is currently receiving as an alternative upgrading process and upon the potential for further improvements in process technology and cost reduction. As presented in this report's reference price case, investment in a commercial coal/oil co-processing plant is economic by 2012, and as early as 1999 under a forecast of higher energy prices.

Conclusions and Recommendations

Coal liquids technology has made significant advances over the last two decades and more particularly in the last 5 years. From a long-term supply option with questionable merit, coal liquefaction has reached the stage where it represents a potentially economic and viable supply option for Canada in the mid to latter 1990s. Coal/oil co-processing, the simultaneous conversion of crude bitumen and coal, is an upgrading technology of special near-term merit.

Development of a prototype commercial coal/oil co-processing plant in the United States affords Canada a unique opportunity to gain important information on this technology and to forego a costly R & D

undertaking in the short term. The progress and technical improvements made at the U.S. demonstration plant could conceivably be transferred, with appropriate modifications, to Canada for applications in Alberta, Ontario and Nova Scotia. The development of a commercial coal/oil co-processing plant in the U.S. also provides Canada with a window of opportunity to explore issues of importance to a site-specific assessment of the demonstration of this technology in Canada.

The coal liquids scenarios evaluated in this study assume that Canada independently embarks on its own evaluation and demonstration program. In the near term, this would mean a commitment to a funding level which would permit a thorough understanding of the conversion properties of Canadian coals and particularly inexpensive, low rank Alberta subbituminous coals. Siting and feasibility studies based where applicable on process improvements and prototype demonstration in the United States might then be undertaken and a demonstration facility built to prove processes and economics for Canadian conditions by as late as 1997.

While the estimated cost of a demonstration facility is a significant investment, it is fundamental if we are to fully appreciate the potential role of coal liquids technology in helping to fill Canada's widening supply-demand gap for light crude oil. If the U.S. prototype demonstration facility proceeds as planned, Canada can forego a significant near-term investment and devote its attention to conceptual and economic evaluations for specific coals and siting locations. A research and development commitment to evaluation and appropriate modification of developments in the U.S. and other countries, together with a thorough examination of issues relevant to Canada, would pave the way for a state-of-the-art Canadian demonstration facility. A production start-up date of 1997 is believed a realistic time frame for such a development.

The economic benefits of additional coal development, together with the increased understanding we would gain of Canada's resource potential, underline the importance of a serious R & D commitment to coal/oil co-processing. If international oil prices do rise, as presented in this study's higher oil price case, investment in coal/oil co-processing would be economic in the latter 1990s and considerable work would have to be undertaken in the next few years to ensure that Canada would be in a position to build this capacity using the most appropriate technology.

An important conclusion brought out by the sensitivity analyses presented here is that coal liquids technology could potentially provide a relatively important and near-term Canadian energy supply option. As such, Canada should be actively engaged in addressing the many considerations prerequisite to the construction of a demonstration facility. If demonstration proves the expectations of the two-stage catalytic process configuration, project economics would be significantly improved over the relatively conservative figures presented in this study. This would enhance the need for a demonstration (prototype) plant and the preparatory work preliminary to siting and construction.

In addition, CERI's assessment of coal liquids technology was based on using a discount rate of 12 percent for all supply options considered. This in effect assumes that the project risks for all supply options--reflecting geological risk, process costs, oil prices and social and environmental impacts--are the same for all of Canada's various energy supply options. In fact, they are not equal and reducing the discount rate for coal liquids to account for comparatively lower geological and social risk would act to lower forecast supply costs. This would advance the requirement for initial production of coal-derived synthetic fuels and the preparatory work required for successful implementation in Canada.

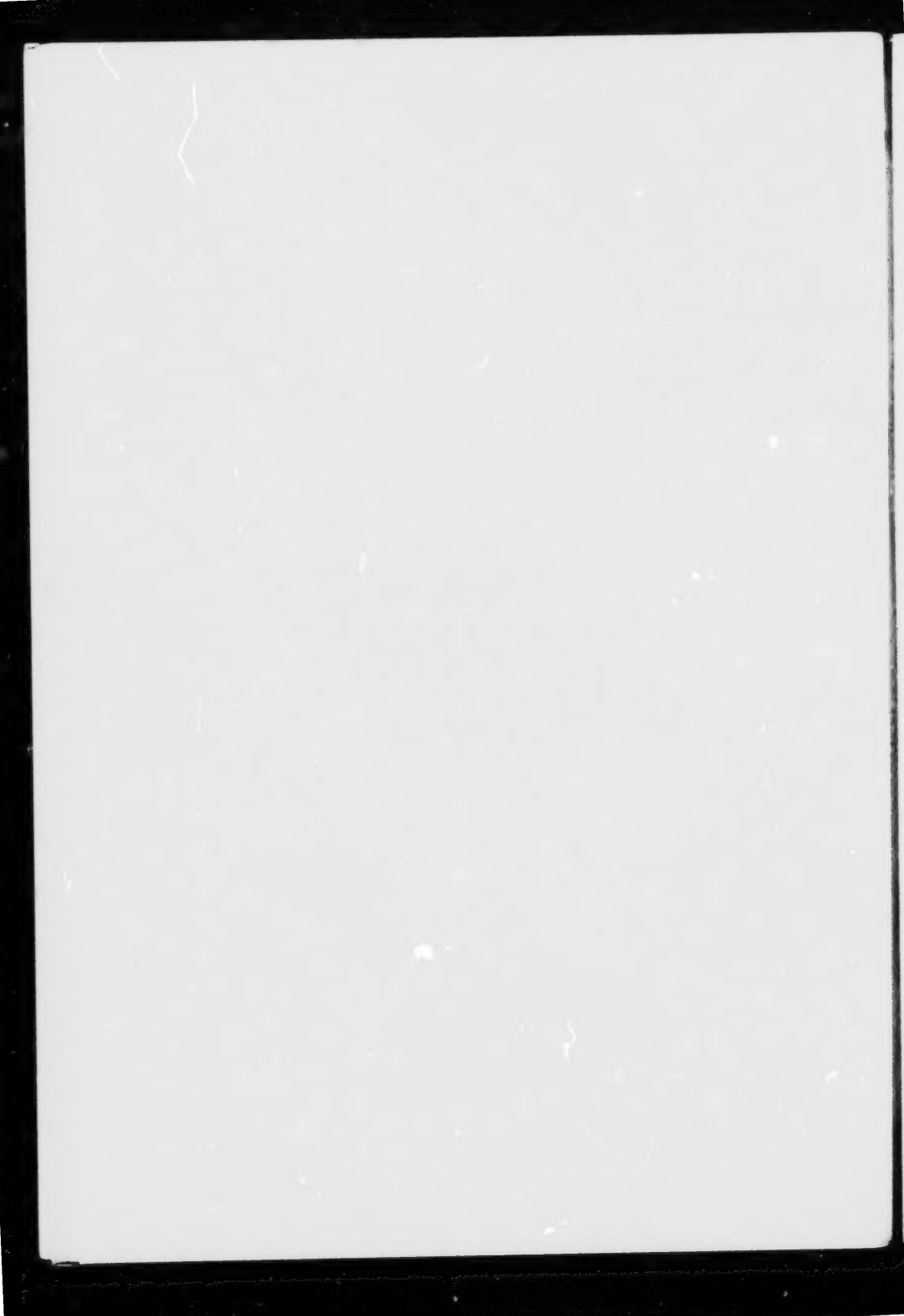
Practical experience with coal/oil co-processing will reduce some uncertainties, allowing the private sector to better assess alternatives and to undertake investment decisions that are more cost-effective and expeditious. Special attention to improving information on Canada's energy supply options is particularly important given the large size of many investments, the substantial uncertainties regarding relative cost and performance, and the demonstrated potential for rapid changes in energy markets.

Because of the complex technical nature and capital intensity of this technology, the decision to have in place the capability to produce coal-derived synthetic fuels must be taken well in advance of their physical requirement. The decision must be a strategic planning initiative. This course of action is difficult in the current economic climate and the situation is exacerbated by some perceptions of secure and inexpensive oil supplies for many years to come. However, as R & D is by definition an activity with a medium- to long-term horizon, it is important to look beyond current market conditions in assessing the potential benefits of R & D activity. The analytical evaluations

presented in this study indicate that coal/oil co-processing (and direct liquefaction to a lesser degree) are process technologies which deserve serious recognition and R & D commitment.

Research geared to the evaluation of Alberta subbituminous coal is required now given that coal/oil co-processing could be commercially viable in the 1990s. Canada has a window of opportunity to examine the remaining issues associated with coal/oil co-processing technology and its adaptation to Canadian coals and siting opportunities to ensure that the best and most appropriate technology is installed when required. Coal/oil co-processing affords Canadians further diversification in future energy supplies of light crude oil which is a recognized concern given Canada's declining reserves of conventional crude oil. In addition, coal/oil co-processing would open up new and potentially significant markets for Canadian production of crude bitumen, natural gas and low rank western Canadian coals.

On the basis of the analysis contained herein, it is strongly recommended that the Canadian government and the governments of the major coal-producing regions of Canada combine to facilitate the examination of all relevant issues prerequisite to the eventual construction of a coal/oil co-processing facility. Given the uncertainties, a co-sponsored government-industry initiative would seem to represent the best possible combination of risk exposure and Canadian expertise in such an undertaking.



Chapter 1

PERSPECTIVES ON CANADIAN OIL SUPPLY AND DEMAND

1.1 Canada's Growing Supply-Demand Gap

Petroleum markets are affected by political as well as economic factors, and this explains why projecting future trends in petroleum production, consumption and imports is extremely difficult. Projections are useful, however, because they provide an overview of general trends in the context of specific assumptions regarding the many factors thought to determine conditions in petroleum markets.

Excerpts from a number of recent reports together with some descriptive information on Canada's energy supply base is presented below in an effort to outline likely trends in Canadian oil consumption, production and imports. These projections represent something of a consensus view as to how conditions in the Canadian and world petroleum markets are most likely to unfold in the decades ahead.

Briefly, most forecasts foresee a turnaround in world petroleum market conditions and a sustained increase in inflation-adjusted oil prices sometime during the next decade. The recent decline in oil prices is expected to reduce production by non-OPEC countries, increase world consumption of petroleum, and increase demand for production from OPEC countries. Rising demand for OPEC oil will strengthen OPEC's ability to allocate production quotas and maintain pricing discipline among its member countries.

According to most projections, if present low prices continue for a few years, conditions in Canadian petroleum markets could change profoundly. Domestic production is projected to fall and, as a result, net imports as a percent of total consumption could rise rapidly and negatively affect future Canadian energy security.

1.1.1 National Energy Board

According to an NEB staff report released last year, Canada's reserves of light crude oil from conventional sources are declining and, if prices remain low, there could be a need to import substantial amounts of light oil during the 1990s.¹

In its report, the NEB prepared separate supply forecasts for pentanes plus, synthetic oil, conventional light oil, heavy crude oil, bitumen and frontier production. For analytical purposes, however, these various crudes were classified into two groups: light and heavy. The NEB based its forecasts on two price scenarios: a high-price case using \$27 (\$1986 U.S.) per barrel in 2005 as the basis of its supply forecast, and a low-price case using \$18/bbl (\$1986 U.S.) in 2005.²

Canada has a large oil resource base, but 90 percent of this resource base is bitumen; conventional crude oil and heavy oils constitute only 10 percent, of which half is located in Western Canada and half in the frontier regions. Established reserves of conventional crude oil at 1984 year-end amounted to $741 \times 10^6 \text{ m}^3$ (4622 MMb). Projected reserves additions of conventional light and heavy crude oil for the 1985-2005 period amount to approximately 460 to $610 \times 10^6 \text{ m}^3$ (2894-3838 MMb) in the low and high price cases, respectively.

The NEB projects light oil reserves additions of 325 to $425 \times 10^6 \text{ m}^3$ (2045-2674 MMb), with some 160 to $190 \times 10^6 \text{ m}^3$ (1007-1195 MMb) expected to result from the application of enhanced oil recovery techniques in oil pools discovered to date and the remainder from future drilling activity.

In the high-price case, the NEB estimates that total domestic oil production will be about $240 \times 10^3 \text{ m}^3$ per day (1510 MMb/d) in 2005 as compared to $120 \times 10^3 \text{ m}^3$ per day (755 MMb/d) in the low-price case. The major difference between the two cases is that the high-price case predicts the expansion of bitumen production through the early 1990s and the introduction of frontier supplies and new upgraders from the mid-1990s on.

The NEB concluded in its report that productive capacity from reserves additions of conventional light crude oil is insufficient to replace production under both price scenarios evaluated during the outlook period. In both cases, the supply of light crude oil and

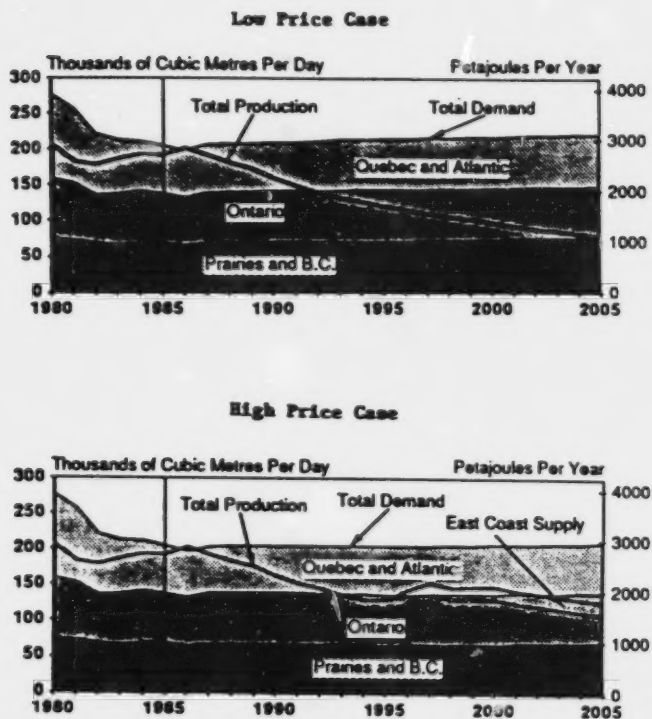
equivalent is projected to decline, so that the 2005 level is expected to be about 40 percent of the 1985 level in the low-price case and 63 percent in the high-price case. In both scenarios, Canada would continue to be a net importer of light and medium crude oil, as reserves from conventional producing areas in Western Canada are depleted. Depending on future prices, Canada is forecast to become a net importer of light and medium crude of between 465,000 and 585,000 b/d by 1995 (36 to 43 percent of projected demand) and of between 370,000 and 750,000 b/d by 2000 (28 to 54 percent of projected demand).³ The greater light crude supplies in the high-price case are expected to accrue from larger conventional reserves additions, frontier supplies (Hibernia), and two upgraders in addition to the Federated Co-op upgrader at Regina assumed for the low-price case (see Figure 1.1).

In a regional context, the degree of energy self-sufficiency varies quite dramatically. In 1986, Atlantic Canada relied on imports for 99 percent of its oil needs while Quebec imported 60 percent of its oil requirements. In the NEB's low price case, virtually all of the oil needs of Quebec and the Atlantic provinces would be met from imports by the mid-1990s and 56 percent of Ontario's oil requirements would be imported by 2000. In the NEB's high price case, Quebec would continue to import all of its oil needs. Atlantic Canada, however, is forecast to import only 29 percent of its oil requirements, and Ontario only 9 percent of its needs, by 2000, as East Coast and Beaufort production comes on stream. Both of the NEB's scenarios suggest that by 2000, transportation will account for about two-thirds of our total oil consumption. The Atlantic provinces are expected to remain more dependent on oil in the residential, commercial, and industrial sectors than the rest of Canada in both price scenarios.⁴

1.1.2 House of Commons Standing Committee on Energy, Mines and Resources⁵

In late 1987, the House of Commons published a wide-ranging assessment of Canada's future production of oil and made a number of recommendations to enhance Canadian energy security. As reported by the Standing Committee, the periodic evaluations of petroleum resources conducted by the Geological Survey of Canada (GSC) suggest that Canada's potential to develop additional reserves of conventional oil (and gas) is substantial.⁶ However, the greater part of this potential is considered to lie in Canada's frontier regions--particularly in

Figure 1.1
Supply and Demand - Light Crude Oil



SOURCE: National Energy Board, *Canadian Energy: Supply and Demand 1985-2005* (Ottawa: Supply and Services Canada, 1986), p. 93.

the East Coast offshore and the Mackenzie Delta/Beaufort Sea (see Figure 1.2). The Arctic Islands, although viewed primarily as a gas-bearing region, also have a significant oil potential. Frontier oil and gas are generally considered exploitable at prices ranging upwards from about \$20/bbl (U.S.).

Canada's Western Sedimentary Basin, although a mature petroleum-producing region, still has substantial potential particularly for natural gas. It is expected that future oil discoveries will tend to be smaller in size and harder to find, with correspondingly higher finding and production costs.

The GSC projected in 1985 that the remaining potential (average expectation) of 3.7 billion barrels of light and medium crude oil would be distributed over 4,000 pools, compared with established reserves of 14.2 billion barrels (9.9 billion barrels produced and 4.3 billion barrels remaining) of light-medium crude distributed over 3,300 pools. Given that future pools are expected to be smaller and more difficult to locate, the GSC concluded that there will be a lower success rate for wildcat wells and it may take as many exploratory wells to locate the last 24 percent of Western Canada's light-medium crude oil resource as it took to find the first 76 percent (see Table 1.1).

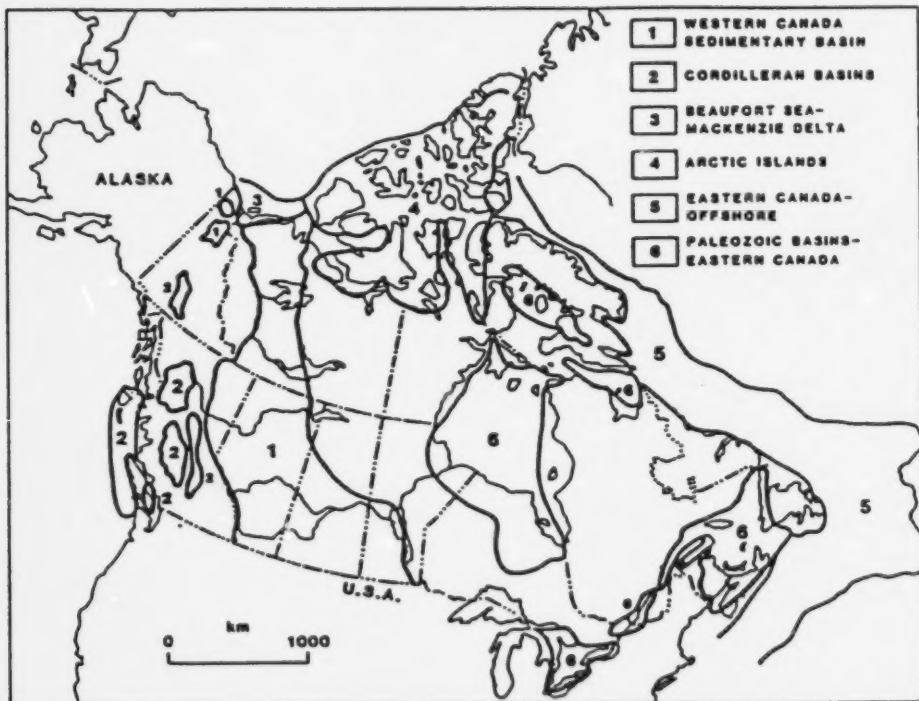
Canada's non-conventional petroleum resources are large. Canada's deposits of bitumen are by far the largest in the world, and lie almost entirely in Alberta (see Figure 1.3).

A recent study of world heavy petroleum resources accords Canada 82 percent of the bitumen resource--an estimated 2.66 trillion barrels of bitumen in place out of a global total of 3.2 trillion barrels. This compilation includes the combined bitumen resources of the oil sands and the "carbonate triangle," carbonate rocks lying beneath the oil sands deposits. Crude bitumen accumulations exist in these carbonate rocks and have become known as carbonate oil. These accumulations are not producible in the foreseeable future.⁷

According to the GSC, the quantity of bitumen contained in the oil sands is almost 1.25 trillion barrels ($197\ 590\ 10^6\text{m}^3$), but only a small fraction of this is considered to be ultimately recoverable.

As cited in the Standing Committee report, the Alberta Energy Resources Conservation Board (ERCB) estimates crude bitumen in place in designated oil sands deposits at 1.69 trillion barrels ($268\ 10^9\text{m}^3$).

Figure 1.2
Canada's Petroleum Regions



SOURCE: House of Commons Standing Committee on Energy, Mines and Resources, Oil Scarcity or Security, Eighth Report to the House of Commons (Ottawa: Standing Committee on Energy, Mines and Resources, 1987), p. 78.

TABLE 1.1
CANADA'S CONVENTIONAL OIL
AND NATURAL GAS RESOURCES

	Reserves and Discovered Resources ^a	High Confidence ^b	Potential Average Expectation ^b	Speculative Estimates ^b
Recoverable Oil (millions of barrels)				
Western Canada Sedimentary Basin	4,743	1,472	3,730	7,611
Cordilleran Basins	-	-	315	692
Beaufort Sea/Mackenzie Delta	736	1,931	8,473	16,933
Arctic Islands	478	1,988	4,315	8,208
Eastern Canada Offshore	1,415	3,220	11,806	21,336
Paleozoic Basins-Eastern Canada	5	126	1,050	3,805
Totals ^c	7,377	*9,347	*29,689	*56,579
Recoverable Gas (billions of cubic feet)				
Western Canada Sedimentary Basin	74 518	54 503	88 391	174 029
Cordilleran Basins	-	1 412	9 531	26 828
Beaufort Sea/Mackenzie Delta	10 096	30 746	65 835	144 836
Arctic Islands	12 473	38 830	79 672	129 269
Eastern Canada Offshore	1 415	3 220	11 806	21 336
Paleozoic Basins-Eastern Canada	311	1 624	6 707	23 298
Totals ^c	106 359	*153 273	*335 668	*645 461

SOURCE: House of Commons Standing Committee on Energy, Mines and Resources, Eighth Report, Oil Scarcity or Security, Ottawa, 1987, p. 79.

^aEstablished reserves are included in discovered resources.

^bThe oil or gas potential is expressed at three levels of confidence: (1) high confidence or a 95 percent probability that the quantity of recoverable oil or gas exists in the region analysed; (2) average expectation or a 50 percent probability of existence; and (3) speculative estimates or a 5 percent probability of existence. The extent to which this resource potential will be converted into reserves is a function of future petroleum exploration activity. Also, the estimate of potential does not include an assessment of economic viability.

^cTotals preceded by a * do not add arithmetically but must be summed using statistical techniques.

Figure 1.3
Oil Sands, Deep Basin Gas, Heavy Oil and
Carbonate Oil Deposits of Western Canada



SOURCE: House of Commons Standing Committee on Energy, Mines and Resources, Oil Scarcity or Security, Eighth Report to the House of Commons (Ottawa: Standing Committee on Energy, Mines and Resources, 1987), p. 80.

The Board further calculates that the ultimate volume of crude bitumen in place within Alberta is 2.52 trillion barrels ($400 \times 10^9 \text{ m}^3$). Of this 2.52 trillion barrels of bitumen considered to comprise the total resource, the ERCB estimates that 170 billion barrels ($27 \times 10^9 \text{ m}^3$) is contained within deposits that may eventually be exploitable by surface mining; the remaining 2.35 trillion barrels ($373 \times 10^9 \text{ m}^3$) occurs in deeper deposits, the exploitation of which would require in situ recovery or underground mining techniques. The initial mineable volume of crude bitumen in place was established at approximately 75 billion barrels ($11.9 \times 10^9 \text{ m}^3$). Allowing for various factors, including a combined mining/extraction recovery factor of 0.79, the ERCB sets initial established mineable reserves of crude bitumen at 33.3 billion barrels ($5.3 \times 10^9 \text{ m}^3$).

Canada's heavy oil deposits are modest on a global scale but important in the domestic resource picture. A 1985 report, sourced by the Standing Committee, shows Canada holding 1.3 percent of the world's heavy oil resources, a total of 11.3 billion barrels initially in place out of a global estimate of approximately 880 billion barrels.⁸ About 750 million barrels is estimated to be initially recoverable, of which 438 million barrels had been produced at the time of the study. Even though a limited component of the Lloydminster heavy oil deposits can be produced by conventional means, the GSC regards the overall heavy oil resource as nonconventional. Due to the uncertainties of extracting heavy oil, the GSC observed that estimates of the total percentage of the resource which will be recoverable are highly cost-price dependent and consequently they were not included in their assessment.

Large accumulations of natural gas are known to exist in the deeper, western-most part of the Western Sedimentary Basin. This gas occurs in "tight" formations--rocks with very low porosity and ultra-low permeability. Production of this tight, deep basin gas would require massive hydraulic fracturing of the reservoir rocks. Where the deep basin gas is in contact with more conventional reservoirs, there is a better prospect of the gas being economically recoverable. The GSC has not yet evaluated Canada's deep basin gas potential, but industry estimates ranging as high as 30 trillion cubic feet ($8,500 \times 10^9 \text{ m}^3$) have been published.⁹

Canada's deposits of oil shales are widely distributed across the country and most have not been investigated in any detail. The best known oil shale deposits are found in New Brunswick and are not

considered economically exploitable at current oil prices. Reserves estimates suggest that more than 283 million barrels ($45 \times 10^6 \text{ m}^3$) of shale oil are in place in the New Brunswick deposit.

The overall picture then is one of limited resource potential for light-medium crude oil reserve additions in Western Canada; a substantial potential for conventional oil development in Canada's higher-cost frontier regions; and a very large potential for high-cost nonconventional oil development, with its requirement for oil upgrading, in Western Canada.¹⁰

The House of Commons Committee report noted that Canada is fortunate in having more options than many countries in handling the question of light crude oil availability.

On the supply side, Canada has two means of augmenting light crude oil availability beyond what remains to be recovered in the Western Canada Sedimentary Basin. Conventional light crude supplies can be extended by developing the new reserves which have been established in the East Coast offshore and in the north. These deposits are expensive to exploit and the quantity of recoverable oil discovered to date is not sufficient to sustain a level of production able to offset the projected decline in Western Canadian light crude deliverability.¹¹

The Committee stressed that the petroleum industry must achieve the highest recovery rates feasible in extracting Canada's conventional oil resources and pointed to enhanced recovery techniques as a means of slowing the decline in light crude production.

The other way to increase supply is to develop Canada's huge resources of bitumen and substantial deposits of heavy oil. Because these heavy hydrocarbons are more difficult and costly to produce and process than light gravity oils, the price of oil is a critical factor in their availability. Bitumen and heavy oil must be upgraded into the light petroleum products we require. The economic feasibility of this upgrading is a function both of oil prices in general and of the differential between light and heavy crude prices. Given recent prices, oil upgrading has not been an attractive prospect.¹²

Canada currently exports most of its growing heavy oil and bitumen production, diluting it with pentanes plus so that it can be pipelined to the United States without need of upgrading. There are, however, limits to extending this type of production. First, the

domestic demand for these heavy oils is not large and is forecast to grow only slowly. Second, the U.S. northern tier market could become saturated. Third, there may be constraints on the amount of diluent available to pipeline the unprocessed heavy oil and bitumen. The continued expansion of Canada's bitumen and heavy oil production is ultimately predicated on developing a domestic upgrading capacity beyond what now exists in the processing capabilities of the integrated Syncrude and Suncor oil sands plants. If greater domestic capability to process heavy petroleum fuels can be established, then Canada's heavy hydrocarbon resources would be adequate to satisfy our demand for petroleum products for decades.

On the the demand side, the Committee pointed to: conservation, the use of natural gas and coal to substitute for oil, and the exploitation of new forms of energy--principally renewable energy supplies--as replacements for oil. The Committee also stressed the importance of research, demonstration, and development support of innovative energy technologies to reduce the costs of these options and to increase the efficiency of energy utilization.

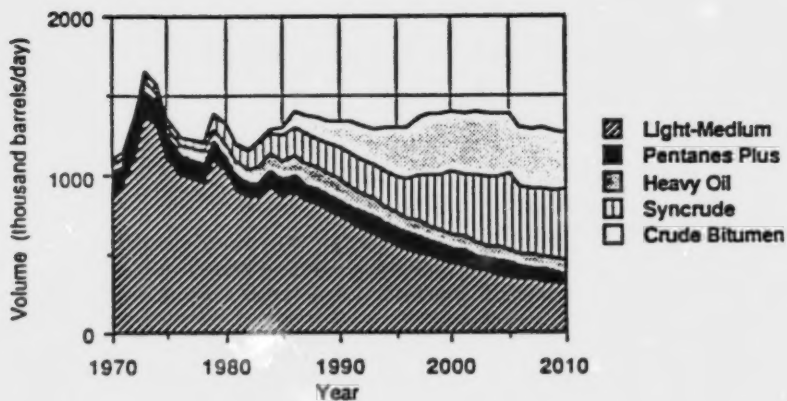
1.1.3 Alberta Energy Resources Conservation Board

In 1986, Alberta accounted for 83 percent of Canada's conventional oil output and 100 percent of bitumen and synthetic crude oil output, equivalent to 88 percent of Canada's total production of oil. In addition, Alberta accounts for 76 percent of Canada's remaining reserves of conventional oil which would be economically producible with current technology.¹³ The ERCB has projected Alberta's oil production to the year 2010 (see Figure 1.4) and expects conventional crude oil output in 2010 to be at only one-third of the 1986 rate. Bitumen production, in either crude or refined form, is expected to account for the major part of Alberta's oil output beyond the turn of the century.¹⁴

Based on a recent ERCB assessment, the reserves-to-production ratio for Alberta's conventional crude oil was estimated at only 12 years. This is an indication of the adequacy of current reserves in relation to current production levels.

After accounting for all reserve additions resulting from new wells, and from enhanced recovery schemes, plus the results

Figure 1.4
Alberta's Oil Production Projected
to the Year 2010



SOURCE: House of Commons Standing Committee on Energy, Mines and Resources, *Oil Scarcity or Security*, Eighth Report to the House of Commons (Ottawa: Standing Committee on Energy, Mines and Resources, 1987), p. 81.

of a 1986 reassessment of the reserves in existing pools, additions to Alberta's reserves of conventional crude oil amounted to 39 million cubic metres, down from 64 million cubic metres in 1985. Alberta produced 53 million cubic metres of conventional crude oil in 1986, a net reserves downsizing of 14 million cubic metres.¹⁵

1.1.4 Synopsis

As noted in the excerpts provided above, geology and geography have provided Canada with vast and diverse energy resources. At present rates of production, Canada has enough proven oil reserves to last about 10 years, uranium to last more than 20 years, natural gas to last more than 35 years, and coal to last in excess of 100 years. Beyond this lie significant potential reserves of these resources. Potential oil sands reserves, for example, are equivalent to the combined proven reserves of the three largest OPEC producers - Saudi Arabia, Kuwait and the United Arab Emirates. However, economically recoverable oil sands reserves at this time translate to only 8 to 12 percent of our potential reserves. Canada's offshore and northern territories are estimated to have discovered crude oil reserves equivalent to almost 5 years of current production and a much greater long-term potential. Canada is also endowed with enormous reserves of coal, concentrated in Alberta and British Columbia.¹⁶

All parts of Canada rely on petroleum to meet their energy needs. In total, petroleum represents almost 40 percent of Canada's primary energy consumption, ranging from a high of 68 percent in the Atlantic provinces to a low of 34 percent in the Prairie provinces.¹⁷

While Canada has been relatively successful in reducing its reliance on oil, domestic requirements for light crude oil will continue to grow and, as a result, Canada seems likely to become increasingly dependent on oil imports. In the NEBs low price case, imports by 2005 could be as much as $142 \times 10^3 \text{ m}^3/\text{d}$ (893 Mb/d), some 64 percent of total domestic light crude requirements. In the high price case, the import requirement is $84 \times 10^3 \text{ m}^3/\text{d}$ (528 Mb/d) or 40 percent of total domestic light crude oil requirements.

The forecast decline in conventional oil reserves means that Canada's domestic oil production will come increasingly from non-conventional and frontier oil reserves. The high cost of production from these sources, together with the lower and more uncertain outlook

for oil prices, suggests that profit margins on projects will be lower and the attendant risk of these projects will be very high.

As Canada becomes more dependant on less accessible and high cost energy supplies, new technology will be called upon to play an increasingly important role. New technologies will be vital in enabling the use of a variety of energy sources for the same end use and in acting to mitigate the adverse environmental impacts of energy resource development.

Projected growth in world crude oil demand together with a forecast reduction in non-OPEC supplies heralds the prospect of higher real oil prices in the future and the attendant costs of supply disruptions which translate to potentially significant, yet uncertain economic costs to the Canadian economy. These costs are uncertain as virtually all the variables--supply, demand, oil price, conservation, the probability and extent of an oil supply disruption--are subject to a high degree of forecast uncertainty. While the costs of growing reliance on OPEC oil supplies is highly uncertain, the potential costs are a direct function of our reliance on imports and virtually all forecasts indicate Canada's future dependency could be high.

There is a broadly based concern that such dependency may not be in Canada's best interests, and various government and private sector interests have explored how best to maintain Canadian energy security. Government assistance to reduce energy project risk has been the solution most often proposed, as the existence of monopolies, a highly concentrated industrial structure, technological change, and the high startup costs and risks associated with major new energy projects could prevent private investment in the energy sector from reaching the level that is economically optimal.

1.2 Prescriptions

Canada's Standing Senate Committee on Energy and Natural Resources some years ago, in a period of lesser concerns with oil price volatility and the adequacy of Canadian oil supplies, portrayed its apprehension over Canada's widening supply-demand gap in the following statements:

Complacency is invading energy policy-making. With the current glut of crude oil in world markets, we see little

concern about future security of supply. But petroleum is not simply another economic commodity whose availability will be adequately regulated by the workings of the marketplace. We reject the premise that energy in its various manifestations, is nothing more than an article of commerce; at times environmental, social, strategic, or political considerations hold sway over market forces.

The Committee and the government have a responsibility to look beyond day-to-day events and to consider longer-term possibilities. To that end government policy-making should be more concerned with the broad direction of Canadian energy development and less with the details of the marketplace. Oil is no less a strategic commodity today than it was in the 1970s ... The oil problem has not disappeared; it is merely dormant. This period of relative calm should be used to plan carefully for a more secure energy future, one which minimizes the importance of oil and our reliance on imports.¹⁸

The Committee stressed that Canadians still do not give sufficient thought to the strategic realities of world energy distribution and trade. It noted that an increasing percentage of world petroleum production is centered in regions such as the North Sea which do not have the reserves to sustain present rates of output far into the future. As Middle East reserves become more dominant in the global picture, there will be an eventual reappearance of uncertain supply conditions with Middle East producers being able to exert heavy pressure on world markets.¹⁹

The potential for terrorism, war or other forms of instability in the politically volatile Middle East could undermine international energy security and Canada's vulnerability to such disruptions. As such, the Senate Committee emphasized that Canada's long-term interests would be best served by making the domestic energy system less vulnerable to events abroad.

To ensure security of energy supply, the Committee specifically recommended:

- an interim floor price for oil sands and enhanced oil recovery production in the event of a sudden large decrease in the price of oil;
- interim protection for consumers against a sudden large increase in the price of oil;

- expansion of conservation efforts by the Federal Government and its continued encouragement of the substitution of other energy forms for oil; and
- the Federal Government's support of alternative energy research and development at a level sufficient to maintain and enhance the leading position that Canada has achieved and in recognition of the export opportunities that it represents.

The House of Commons Standing Committee report on oil security recently echoed many of these same concerns. It recommended that the Federal Government establish a government-owned strategic petroleum reserve (SPR) equal to a 90-day supply of net light crude oil imports to provide some protection against short-term disruptions in the supply of imported oil.²⁰ The Committee asserted that this capability is required because supply disruptions will become increasingly likely as Persian Gulf states regain domination of world production in the years ahead. With production of domestic light crude declining, Canada will become more vulnerable to any curtailment in offshore supplies.

The Committee acknowledged that a SPR provides some protection against short-term disruptions in the supply of imported oil, but noted that it does not address the underlying issue of Canada's deteriorating availability of domestic light crude oil. To reduce the imbalance between domestic supply and demand, the Committee stressed that initiatives to increase the indigenous supply of light oil and to restrain demand for petroleum products should be pursued simultaneously.

The Commons Committee made twelve recommendations in support of enhanced Canadian oil security. Under the research and development heading, they specifically recommended that:

- the Federal Government should increase its financial support for research, development and demonstration directed to increasing the domestic supply of oil, with particular emphasis on the extraction and upgrading of bitumen and heavy oil and on frontier petroleum development, but also including conventional light oil development through such means as enhanced oil recovery.
- the Federal Government should underwrite part of the cost of research and development designed to ensure that a range of energy options is available in the future, options which the private sector may view as requiring too long a payback period to warrant significant investment

today. The Federal Government has reduced its research, development and demonstration (R,D&D) spending too severely on new energy technologies, alternative energy development and energy conservation.²¹

- the Federal Government increase its financial support for research, development and demonstration to promote the availability of nonconventional energy forms, and to promote the substitution of both conventional and unconventional energy forms for oil. As some of the energy alternatives will require many years of development before their exploitation is feasible, government support of R,D&D is required to ensure that these new energy options are available for our future needs. Canada will also benefit from the export opportunities afforded by these new technologies, particularly in the developing world.²²

1.3 The Potential of Coal-Derived Fuels

The following chapters of this report explore the potential role for coal-derived synthetic fuels in the context of Canada's future energy demand, declining conventional crude oil production and energy technology mix. Coal liquids technologies are considerably lower on the learning curve than the more commonly cited long-term measures for enhancing Canada's energy security, such as integrated oil sands plants, frontier development and heavy oil upgraders. In point of fact, a good deal of information exists on these supply options and the focus of this study is upon the findings and assessment of recent research for this considerably less appreciated potential supply option.

Long-term programs which reduce the level of oil import demand lessen the economic impact of supply disruptions somewhat, by reducing the profile of oil imports in an economy. Such reductions, however, have limited value in reducing immediate price increases and other impacts resulting from a supply disruption. Like other longer-term, capital intensive energy supply options, coal liquids offer little in the way of mitigating the security threat of an oil supply disruption.

Rapid changes in the market price or economic security costs of oil could, however, quickly change the outlook for technologies and energy options that were previously deemed unattractive relative to oil. All-out or surge efforts could be required to deploy energy options that suddenly become economic.

Some prior experience, therefore, with new technologies such as coal-derived synthetic fuels production could enhance Canada's ability to undertake required surge deployment efforts, thereby yielding improved benefits. As a rapid increase in development would not reflect a normal pattern of evolutionary development in production technology, the importance of planning for future supply contingencies as part of Canada's present research program is evident. This may particularly be so for coal liquids technology which potentially could require sizeable investments in research and demonstration.

The potential for rapid change in energy markets may create the need for rapid deployment of energy options other than coal-derived synthetic fuels. However, the benefits of improved capabilities for surge deployment may provide a rationale for special attention to coal liquids due to the long lead-time required to acquire basic experience and improved capabilities.

But because the incentives of the private marketplace alone may not yield sufficient benefits to entice private companies to engage in demonstration of coal liquids technologies, special government efforts and incentives may be justified.

1.4 Conclusions

While all forecasts are inherently subject to error, the relevant issue is appropriate contingency and policy planning for the uncertainties and potential costs that these forecasts suggest for Canadian energy requirements. By most accounts, Canada appears headed on a course which will lead to considerable future reliance on insecure and higher cost OPEC sources of oil in the decades ahead.

It is within this context that recent advances in coal liquids technology are examined in order to explore the potential role that this technology might play in Canada's evolving energy supply mix. As both the Senate and House of Commons Energy Committees noted, research, development and demonstration of promising new technologies are mandatory if we are to plan effectively and enhance Canada's future energy security. The following chapters of this report examine whether coal liquids technology fits the description of new processes which should be actively assessed and demonstrated in the context of Canada's evolving energy options.

Footnotes

¹National Energy Board, Canadian Energy Supply and Demand 1985-2005 (Ottawa: Supply and Services Canada, 1986).

²Energy, Mines and Resources Canada, The Sarnia-Montreal Pipeline: An Evaluation of Prospects (Ottawa: Supply and Services Canada, June, 1987), pp. 9, and 10.

³Energy, Mines and Resources Canada, Energy In Canada: A Background Paper (Ottawa: Supply and Services Canada, November, 1987), p. 57.

⁴Energy, Mines and Resources Canada, Energy Security In Canada: A Discussion Paper (Ottawa: Supply and Services Canada, June 1987), p. iv.

⁵House of Commons Standing Committee on Energy, Mines and Resources, Eighth Report, Oil Scarcity or Security (Ottawa: 1987).

⁶The most recent nation-wide analysis was conducted in 1983. Estimates of Western Canada's resources of conventional light and medium gravity oil were reviewed and revised in 1985.

⁷Ibid., p. 81.

⁸Ibid., p. 81.

⁹Ibid., p. 82.

¹⁰Ibid., p. 82.

¹¹Ibid., p. 88.

¹²Ibid., p. 89.

¹³Energy, Mines and Resources Canada, Energy In Canada, op.cit, p. 19.

¹⁴Alberta Energy Resources Conservation Board, Energy Alberta 1986 (Calgary, Alberta: AERCB), p. 27.

¹⁵Ibid., p. 8.

¹⁶Energy, Mines and Resources Canada, Energy In Canada: An Overview, Discussion Paper (Ottawa: Supply and Services Canada, January, 1987), p. 3.

¹⁷Ibid., p. 6.

¹⁸Senate of Canada, First Session 33rd Parliament, August 21, 1985, Issue no. 19, Proceedings of The Standing Senate Committee on Energy and Natural Resources, Eighteenth Proceedings on The National Energy Program, p. 3.

¹⁹Ibid., p. 15.

²⁰House of Commons Standing Committee, op. cit., p. 5.

²¹Ibid., p. 7.

²²Ibid., p. 8.

Chapter 2

CANADA'S COAL RESOURCES

2.1 Coal Classification

Coal is an extremely complex and variable material whose structure is inadequately understood despite centuries of use. Coal is a fossil fuel formed from plant-derived organic remains plus some inorganic minerals. Under appropriate geo-chemical and geological conditions, plant debris can accumulate to form peat which, in turn, can undergo a progressive transformation commonly termed coalification. As organic matter is coalified by increasing heat and pressure, it is profoundly modified. This increasing maturation is characterized by the progressive loss of volatile matter and increase in carbon content, with an associated increase in heating value.¹

Coals are classified according to their carbon content and their calorific value. The classes, ranging from lowest to highest heating value, are lignitic, subbituminous, bituminous, and anthracitic. Lignitic and subbituminous coals are currently used mainly for thermal power generation but some deposits would also provide suitable feedstocks for coal gasification or liquefaction plants. Bituminous coals can be used for thermal power generation and in some cases for coking in metallurgical industries; anthracitic coals can be used for domestic heating and for special smelting applications. They can also be blended with bituminous coals to improve coking quality.²

The quality of coal is determined in general by two classes of material: (1) the organic remains of plants and (2) inorganic substances contributed by the plants, by water seepage, and by the surrounding geological matter, generally referred to as mineral matter. The organic portion of coal consists of carbon rings linked by chains that contain nitrogen, hydrogen, sulfur, and oxygen. Many products therefore arise when coal is heated. While these products may be commercially useful, they may also be potentially hazardous as they include small amounts of carcinogens, mutagens, and respiratory irritants. The inorganic or mineral portion of coal usually constitutes from 9 percent to about 30 percent of the coal by weight. It includes up to half the sulfur and small, potentially toxic amounts of antimony, arsenic,

beryllium, cadmium, mercury, lead, selenium, zinc, heavy radionuclides, and asbestos.³

The occurrence of potentially exploitable coal is related to a variety of geological factors. Although coal is abundant in Canada, deposits are widely distributed and vary significantly in geological complexity, rank, composition, and properties. As a general rule, the older the coal and the greater its depth the higher its rank. Coals of Canada's plains region are low in rank with modest heating values. Coals of the same age have usually been more deeply buried westward towards the mountains, and deposits in this region are generally of higher rank and heating value. Table 2.1 provides a summary classification of coal by rank according to Standards of the American Society for Testing and Materials.

The problem of assessing deposits as a resource is complicated as coals differ in quality, and are used for different purposes. Some, especially lignites and subbituminous coals, are used mainly for thermal purposes whereas others, particularly the bituminous coals of Canada's mountain region, tend to be agglomerating and so are considered as metallurgical coals. Thermal coals themselves may vary widely in calorific value; one tonne of lignite does not produce as much heat as a tonne of subbituminous coal and still less than one of bituminous coal.

The coals in Saskatchewan are lignitic, averaging about 14 MJ/kg; the subbituminous coals of the Alberta plains range from 15-21 MJ/kg depending on mineral matter content; and the bituminous and semi-anthracite coals of the foothills and the mountain regions of Alberta and British Columbia range from about 25 to 33 MJ/kg. In south central British Columbia, coals range from lignite/subbituminous to bituminous and average about 22 MJ/kg. The coals of Eastern Canada are of a high volatile bituminous rank averaging about 30 MJ/kg.

The heating values of coals diminish as the percentages of contained mineral matter and moisture increase. Heating value is an important factor in determining coal quality though it is by no means the only one. The amount of ash to be disposed of after burning is significant and the fusion temperature of the coal's ash can also affect its utilization. Lignite and sub-bituminous coals contain considerable moisture, an obvious defect.

A major advantage of western coals is their low sulfur content. Almost all Western Canadian coals contain less than

TABLE 2.1
CLASSIFICATION OF COALS BY RANK

Class	Group	VME ^a	PCI ^a	Calorific Values ^b		Principal Uses
				Btu per lb	kJ/kg	
Anthracite ^c	Meta-anthracite	2	98			Small amounts may be blended with bituminous coals for coke-making for steel production. Also used in the chemical industry.
	Anthracite	8	92			
	Semi-Anthracite	14	86			
Bituminous Coal ^d	Low-volatile bituminous	22	78			Coke making for steel production; thermal coal for power generation.
	Medium-volatile bituminous	31	69			
	High-volatile A bituminous			14000	32.6	
	High-volatile B bituminous			13000	30.2	
	High-volatile C bituminous					
Subbituminous ^e Coal	Subbituminous A ^f			11500	26.7	Thermal power fuel, process steam for industry, gasification and liquefaction.
	Subbituminous B			10500	24.4	
	Subbituminous C			9500	22.1	
Lignite ^f	Lignite A			8300	19.3	Thermal power fuel, gasification and liquefaction.
	Lignite B			6300	14.7	

SOURCE: (1) The Coal Association of Canada, 1987 Review and Directory (Calgary: The Coal Association of Canada, 1987) p. 11; and (2) Canada West Foundation, Western Canada's Coal: The Sleeping Giant (Calgary: Canada West Foundation, November 1980), p. 31.

LEGEND: Canada uses the systems and procedures of the American Society for Testing and Materials (ASTM) for sampling, analysing and classifying coals by rank, as detailed in the Annual Book of ASTM Standards. Basically coals are ranked according to their degree of metamorphism, or progressive alteration, in the natural series from lignite to anthracite.

Classification in the ASTM system is a function of fixed carbon content and calorific value calculated on the mineral-matter-free basis. The high rank coals are classed according to calorific value on the moist basis. The agglomerating characteristics of coals (i.e., their binding and/or swelling qualities when heated in the absence of oxygen) are used to differentiate between certain adjacent groups in the ranking.

VM = Volatile Matter
FC = Fixed Carbon

Btu = British Thermal Unit
kJ = MegaJoules

^aDry, mineral-matter-free basis.

^bMoist, mineral-matter-free basis.

^cNon-agglomerating; if agglomerating, classified as a low volatile bituminous.

^dCommonly agglomerating.

^eIf agglomerating, classified as a high volatile C bituminous.

^fNon-agglomerating.

0.5% sulfur and some are as low as 0.2%. Coals in Eastern North America run as high as 5% sulfur and are commonly in the range of 2% to 3%.⁴

Coal-bearing strata are found in most areas of Canada, from coastal British Columbia to the Maritimes and in Northern Canada (see Figures 2.1 and 2.2). In British Columbia, low and medium volatile bituminous coal deposits of the East Kootenay and Peace River regions of the Rocky Mountains and Foothills constitute the majority of Canada's metallurgical coal resource inventory. Several basins in the interior regions of the province contain important thermal coal deposits, such as the Hat Creek lignite deposits. Additional thermal coal deposits occur on Vancouver Island and in the Queen Charlotte Islands.

In Alberta, commercially significant coal resources occur throughout the Rocky Mountains, Foothills and Plains regions. Most coals of the Rocky Mountains are of metallurgical grade, like those of the adjacent East Kootenay and Peace River regions of British Columbia. Large quantities of low sulphur, high volatile bituminous coals occur within the Foothills region and represent high quality exportable thermal coals. Virtually all of Canada's subbituminous coal resources occur within the Plains region of Alberta. The main interest in these thermal coals is currently for mine-mouth power generation.

Coal deposits that are widely distributed throughout Southern Saskatchewan contain most of Canada's lignite resource inventory, a regionally important thermal fuel.

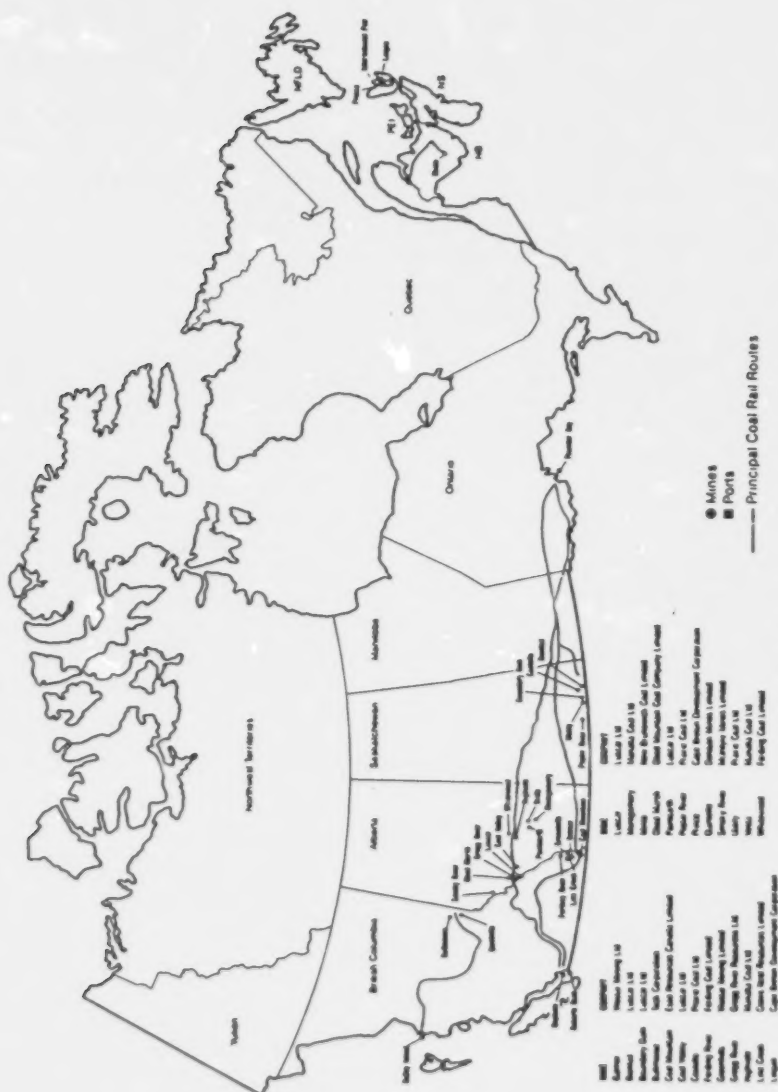
Numerous seams of mainly high volatile bituminous thermal coals occur in New Brunswick, but they are generally thin and have high sulphur contents.

About 1 percent of Canada's measured coal resources of immediate interest occur in Nova Scotia. These resources comprise high volatile bituminous coals of which about 75 percent are thermal grade and 25 percent are metallurgical grade.⁵

2.2 Resources Terminology

While there are variations in how the terms "resources" and "reserves" have been used in recent years, they have tended to be based upon a system jointly adopted by the United States Bureau of Mines and

Principal Canadian Coal Mines



SOURCE: The Coal Association of Canada, 1987 Review and Directory (Calgary, Alberta: The Coal Association of Canada, 1987), p. 14.

Figure 2.2
Principal Coal Deposits



SOURCE: The Coal Association of Canada, 1987 Review and Directory (Calgary, Alberta: The Coal Association of Canada, 1987), p. 10.

the United States Geological Survey. The Federal Department of Energy, Mines and Resources (EMR) uses criteria similar to those used by the World Energy Conference (principal international organization dealing with world energy sources), the U.S. Bureau of Mines and the U.S. Geological Survey.

In Canada, the term "coal resources" is defined as the coal that is contained in seams occurring within specified limits of thickness and depth from surface. The concept of the term "resources" implies that deposits may be mineable now or in the future. In contrast, the term "reserves" implies deposits that are now economically and legally mineable.

The Geological Survey of Canada categorizes the country's estimated coal resources in terms of assurance of existence and feasibility of exploitation. Assurance of existence is expressed in terms of measured, indicated, and inferred, which imply relative levels of confidence in estimated quantities. This confidence level is based on distributions of available data, and the assumption that resource definition near observation points is more reliable than that which is more remote. Feasibility of exploitation is expressed in terms of resources of immediate interest and resources of future interest where: (1) resources of immediate interest represent in situ coal tonnages of favourable coal seam thickness, quality, depth and location that are considered to be of immediate interest for continuing exploration or development; and (2) resources of future interest represent in situ coal tonnages that, due to less favourable coal seam thickness, quality, depth and/or location are not of immediate interest but may become of interest in the future.

Coal resource assessments are commonly made on the basis of conceptual deposit models which define spatial distributions of geological variables. Coal quantity is determined by multiplying areal extent of the coal bed by its thickness. The resulting volume is multiplied by estimated bulk density of the coal to derive tonnage.

Although the principles for estimating coal quantities are fundamental, there are no universal standards for classifying these quantities according to criteria which imply either confidence in the estimates, or relative exploitation potential of the coals. Individual coal companies and provincial government agencies within Canada assess coal resources inconsistently.⁶

Under Energy, Mines and Resources criteria, coal resources are defined as follows:

Measured Resources are tonnages computed from dimensions revealed in outcrops, trenches, mine workings and boreholes. In general, the points of observation should be separated by less than the following distances: Cordillera: 300 metres (150 metres in severely contorted areas); Plains: 800 metres.

Indicated Resources are tonnages computed partly from specific measurements and partly from reasonable geological projections. In general, points of observation should be separated by less than the following distances: Cordillera: 600 metres (300 metres in severely contorted areas); Plains: 1600 metres.

Inferred Resources are resources for which quantitative estimates are based largely on broad knowledge of the geological character of the bed or region and for which few measurements of seam thickness are available. These estimates are based primarily on an assumed continuity of coal seams in areas remote from points of observation used to calculate measured or indicated resources.

Speculative Resources are resources for which quantity estimates are based on information from a few scattered occurrences. Resources of this description are mainly in frontier areas where coal mining or exploration have not taken place.

Depth and thickness of the seams are also part of the criteria determining whether or not coal is classified as a resource.⁷

The criteria for classifying coal resources differs widely between agencies and this has resulted in substantial differences in estimates of coal tonnages. The criteria and terminology used by the Alberta Energy Resources Conservation Board (ERCB) differs significantly from those used in the United States and by EMR in Canada, where the terms measured, indicated and inferred are used. The principal terms and meanings used by the ERCB are:

- Resource - A gross quantity of coal calculated, interpreted, or presumed to exist in the ground.
- Established Resource - A body of coal that has been specifically delineated by drilling, trenching, driving audits, mine development operations or other

exploratory work, but including some judged to exist contiguously on the basis of geological, seismic or similar information.

- Reserve - That portion of an established resource considered recoverable by current technology under present or anticipated economic and social conditions.
- Initial In-Place - The quantity of a resource prior to any production.
- Initial Reserve - A reserve prior to deduction of any production.
- Remaining Reserves - The initial reserve less cumulative production.
- Ultimate Potential - An estimate of the initial reserves which will become developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of that area and anticipated technological, economic and social conditions. Ultimate potential includes cumulative production, remaining reserves and presumed future additions through extensions and revisions of existing deposits, and the discovery or delineation of new deposits.⁸

The ERCB defines "reserves" as those resources that can be considered recoverable by current technology under present or anticipated economic and social conditions. Criteria for distinguishing reserves consequently vary through time. The ERCB calculates the size of reserves only in areas where extensive data are available and where the extent of the coal deposit is known in considerable detail. The Geological Survey of Canada classifies a "reserve" as that portion of a resource estimate which has a high degree of geological assurance and a high degree of immediate economic interest. This lack of standardization leads to problems in understanding precisely what is meant by the terms measured resources or established reserves, and in significant differences in estimates of coal potential.⁹

2.3 Resource and Reserves Estimates

Data on Canada's coal resources, as compiled by the Geological Survey of Canada from its own data and by provincial sources, is shown in Table 2.2. Estimates of Canada's recoverable reserves are summarized by province in Table 2.3.

TABLE 2.2
ESTIMATES OF COAL RESOURCES IN CANADA
(megatonnes)

Area	Coal Rank ^a	Resources of Immediate Interest			Resources of Future Interest		
		Measured (1)	Indicated (2)	Inferred (3)	Measured (4)	Indicated (5)	Inferred (6)
Nova Scotia^c							
Sydney	hvb	156 ^b	1 428 ^d	719	-	-	-
Other	hvb	48	41	38	3	50	128
Subtotal		204	1 469	757	3	50	128
New Brunswick^d							
Minto	hvb	6	13	-	-	-	-
Other	hvb	14	14	1	-	-	-
Subtotal		20	27	1	-	-	-
Ontario^e	lig	218	-	-	-	-	-
Saskatchewan^f							
Estevan	lig	283	497	437	41	519	6 998
Willow Bunch	lig	747	1 044	1 420	68	1 704	10 388
Wood Mountain	lig	278	733	1 114	44	1 447	5 865
Cypress	lig	162	407	465	8	243	461
Subtotal		1 470	2 681	3 436	161	3 913	23 512
Alberta^g							
Plains	sub (& some hvb & lig)	41 860 ^h	- ⁱ	- ^j	-	-	1 750 000 ^k
Foothills	hvb	2 490	-	5 010 ^k	-	-	7 500 ^l
Mountains	lvb-mvb (& some hvb)	7 760	-	6 740 ^l	-	-	14 500 ^o
Subtotal		52 110	-	11 750	-	-	1 772 000
British Columbia^p							
Southeastern	lvb-mvb	6 286	9 436	36 317	-	-	-
Northwestern	lvb-mvb	996	462	7 719	-	-	-
Other	mainly lig	-	-	-	-	-	-
Subtotal	(& some sub-hvb)	1 845	91	7 439	-	-	-
		9 127	9 989	51 475	-	-	-
Canada - Totals							
	lig	3 533	2 772	10 875	161	3 913	23 512
	sub	41 860	-	-	-	-	1 750 000
	hvb	2 714	1 496	5 768	3	50	7 628
	lvb-mvb	15 042	9 898	50 774	-	-	14 500
	total	63 149	14 166	67 419	164	3 963	1 795 640

SOURCE: National Energy Board, Canadian Energy Supply and Demand, 1985-2005 (Ottawa: Supply and Services, 1986), p. 350.

^alig - lignitic; sub - subbituminous; hvb - high volatile bituminous; mvb - medium volatile bituminous; lvb - low volatile bituminous.

^bResources from ER/9-9 less production between 1978 and 1982.

^cBased on federal/provincial drilling program and data from Cape Breton Development Corp.

^dBased on data by New Brunswick Department of Natural Resources and M.B. Coal Ltd.

^eBased on ENR study.

^fBased on federal/provincial coal resource evaluation program in 1978, less production to 1984.

^gEstimates for Alberta are based on Energy Resources Conservation Board Report 84-31. Work by Williams and Murphy, 1981, indicates the ERCS estimates up to December 1980 and earlier have been excessively conservative in identifying total coal resources for the Plains regions. Accordingly, ERCS has accepted the tenfold increase in resource tonnage for plains coal as more realistic than earlier estimates. Note that ERCS's parameters, evaluation methodology and reporting terminology differ from those used by ENR.

For this table, the following accommodations have been made:

^hERCS "established resources" are reported as ENR "measured resources"; it is recognized these figures include some tonnage that ENR would report as "indicated."

ⁱThere is no ERCS category comparable to ENR "indicated."

^jThere is no ERCS category comparable to ENR "inferred resources of immediate interest."

^kRepresents one-half of ERCS "total resources" (15.0 gigatonnes) less all of ERCS "established resources" (2.26 gigatonnes).

^lRepresents one-half of ERCS "total resources" (29 gigatonnes) less all of ERCS "established resources" (7.76 gigatonnes).

^mRefers to resources identified by Williams and Murphy, 1981, for all five Reliability Index categories for seams 2 metres thick from base of surface casing (9-150 m) to 300 metres deep.

ⁿRepresents one-half of ERCS "total resources" (15 gigatonnes).

^oRepresents one-half of ERCS "total resources" (29 gigatonnes).

^pBased on evaluations by ENR, British Columbia Ministry of Energy, Mines and Petroleum Resources and British Columbia Hydro.

^q"Demonstrated" resources of Macquhard (1983) less "measured resources" reported in ER/9-9.

TABLE 2.3
RECOVERABLE RESERVES OF COAL
BY PROVINCE AND CLASS

Province	Class	Megatonnes	Peta Joules
British Columbia	Lignite	566	8 688
	Bituminous	2 098	61 471
Alberta	Subbituminous	918	18 140
	Bituminous	526	15 412
Saskatchewan	Lignite	1 697	26 049
New Brunswick	Bituminous	18	547
Nova Scotia	Bituminous	445	13 039
Canada - Totals	Lignite	2 263	34 737
	Subbituminous	918	18 140
	Bituminous	3 087	90 449
	Total	6 268	143 326

SOURCE: National Energy Board, Canadian Energy Supply and Demand, 1985-2005 (Ottawa: Supply and Services, 1986), p. 105.

NOTE: The numbers in this table have been rounded.

Coal resources are divided into two main categories depending on whether they are of immediate or future interest. Resources of immediate interest must consist of coal seams with combinations of thickness, quality, depth and location which render them attractive for immediate exploration or development.

Resources of immediate interest are estimated to be 145 gigatonnes (3500 exajoules) and those of future interest 1800 gigatonnes (43 000 exajoules). These two categories are further subdivided into measured, indicated and inferred resources which denote decreasing levels of confidence in the estimates. Resources of future interest are almost all inferred whereas more than 50 percent of the resources of immediate interest are measured and indicated.

Recoverable coal reserves consist of that part of measured and indicated resources of immediate interest that are considered to be, with reasonable certainty, recoverable. For deposits to qualify as reserves, amongst other criteria, feasibility studies must have been done, specific plans for mining method and processing adopted and the overall economic feasibility for development appear favourable.¹⁰

Total recoverable reserves depicted in Table 2.3 are estimated as 6 268 megatonnes which is about 100 times Canada's annual coal production. Of these reserves almost two-thirds are located in British Columbia and Alberta and some 90 percent are estimated to be recoverable by surface mining methods.

In contrast to these figures, the ERCB estimates that Alberta's remaining in-place established resources of all types of coal total about 67 gigatonnes. Of this amount, about 26 gigatonnes are considered to be recoverable by surface and underground methods. Subbituminous and minor lignite represent 21 gigatonnes of total recoverable reserves of which 7.7 gigatonnes are recoverable by surface mining methods.

Canada's coal reserves represent the largest proven reserves of any energy resource in Canada. Estimates of Canadian reserves compiled by the ERCB indicate that Canada's coal reserves at the end of 1986 contain 2.3 times the energy of all other non-renewable energy resources combined (see Table 2.4).

TABLE 2.4
ALBERTA VS. CANADIAN RESERVES AND PRODUCTION
(petajoules)

	Alberta	All of Canada	Percentage Reserves in Alberta
<u>Remaining Reserves at the End of 1986</u>			
Conventional Oil and Equivalent	24 940	33 300	75
Natural Gas and Equivalent	71 060	86 360	86
Bitumen and Synthetic			
Crude Oil	154 000	154 000	100
Coal	495 000	640 000	77
Total	745 000	913 660	81
<u>1986 Production</u>			
Conventional Oil and Equivalent	2 250	2 700	83
Natural Gas and Equivalent	2 500	2 700	92
Bitumen and Synthetic			
Crude Oil	620	620	100
Coal	580	1 450	40
Hydro	5	1 040	0
Nuclear	-	190	0
Total Production	5 955	8 700	68

SOURCE: Energy Resources Conservation Board, Energy Alberta 1986,
 ERCB 87-40 (Calgary: Energy Resources Conservation Board), p. 27.

Canada's coal resource base indicates that much of the potential application of new coal liquids technologies would appear to lie in Alberta, given its potential coal, natural gas and heavy oil resource base. Alberta's reserves of conventional oil, natural gas, bitumen, synthetic crude oil and coal constitute over 80 percent of Canada's total non-renewable remaining reserves at the end of 1986 (see Table 2.4).

While coal liquids facilities need not necessarily be located within Alberta, Alberta's coal resource base together with natural gas for upgrading would offer some significant comparative advantages in large-scale production of synthetic fuels from coal.

Footnotes

¹Dr. W. W. Nassichuk, Examination of the Production and Use of Coal in Canada, Presentation to the Standing Senate Committee on Energy and Natural Resources, May 11, 1987, Issue no. 8, p. 8:37.

²National Energy Board, Canadian Energy Supply and Demand: 1985-2005 (Ottawa: Supply and Services Canada, 1986), p. 105.

³National Research Council, National Academy of Sciences, "Final Report of the Committee on Nuclear and Alternative Energy Systems," Energy In Transition, (San Francisco, California: W. H. Freeman and Company, 1979), p. 150.

⁴Canada West Foundation, Western Canada's Coal: "The Sleeping Giant," Report by An Independent Task Force (Calgary: November 1980), p. 29.

⁵Dr. W. W. Nassichuk, op. cit., p. 8:37, 8:38.

⁶Ibid., p. 8:38.

⁷Energy, Mines and Resources Canada, Coal Mining in Canada, Canada Centre for Mineral and Energy Technology, Report 83-20E (Ottawa: March 1983), pp. 16 and 17.

⁸Alberta Energy Resources Conservation Board, Reserves of Coal: Province of Alberta (Calgary: December 31, 1986), p. 4-1.

⁹C. W. Langenberg, D. E. MacDonald, and R. J. H. Richardson. Geological Studies of Coal in Alberta: A Status Report, Alberta Research Council, Alberta Geological Survey (Edmonton: December, 1986), pp. 9 and 10.

¹⁰National Energy Board, Canadian Energy Supply and Demand: 1985-2005 (Ottawa: Supply and Services Canada, 1986), p. 105.



Chapter 3

COAL LIQUIDS TECHNOLOGY

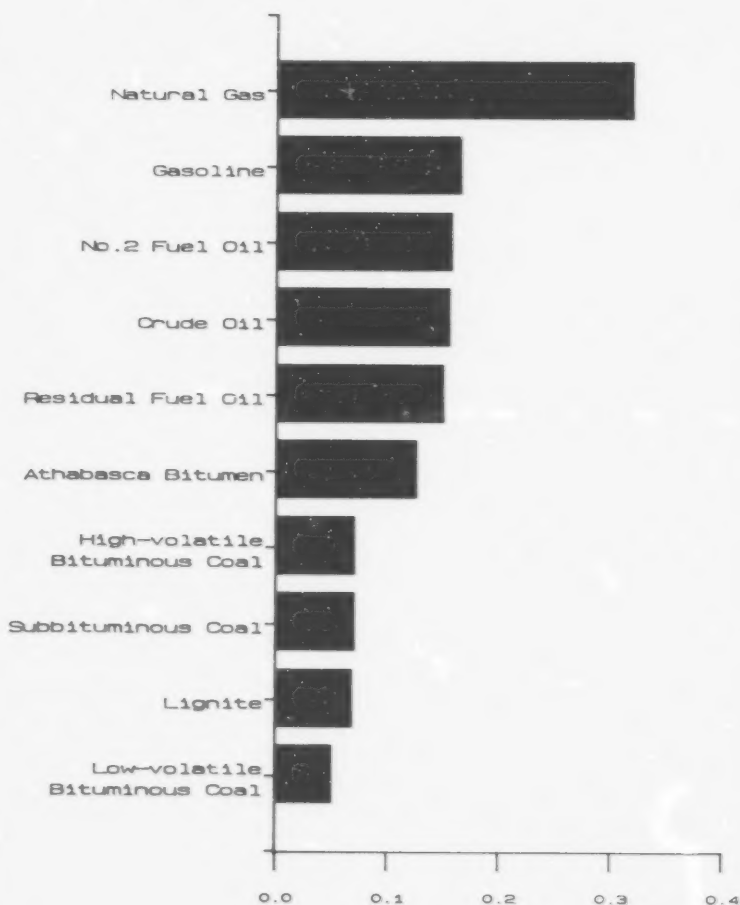
3.1 Coal Liquefaction Basics

Coal is a solid material consisting primarily of carbon and hydrogen with significant amounts of inorganic mineral matter as finely divided constituents and absorbed moisture. In addition, coal contains varying quantities of oxygen, nitrogen and sulphur. Alkali metals and trace elements may also in part be organically bound with the coal itself.

Two important properties of fossil fuels are their ash content and their relative proportions of hydrogen and carbon. Compared with conventional petroleum, coal is hydrogen deficient, containing less than one-half as much hydrogen and far more impurities such as nitrogen, oxygen and ash. The structure of coal depends on the conditions under which it is found and its properties are, therefore, more variable than oil. The sulphur content of coal varies widely, depending on the precise source of the material. Even different samples from a given mine can vary markedly, not only in sulphur content but also in their ash and moisture contents. Figure 3.1 displays typical hydrogen to carbon ratios for a number of common fuels. As shown in the figure, coal's hydrogen to carbon ratio ranges from 0.06 to 0.075, and thus the amount of hydrogen that must be added to upgrade coal to liquid or gaseous products is even larger than that required to upgrade bitumen derived from oil sands.

Being of botanical origin, coal is a geological and chemical cousin to other fossil fuels such as petroleum, oil sands and oil shale. Chemically, however, it is very different as coal has a much lower hydrogen to carbon ratio than in natural petroleum and greater quantities of impurities (see Table 3.1). Coal's makeup affects the reaction conditions and the changes which take place during coal liquefaction and, to a certain extent, the composition of the products obtained from the liquefaction process itself. For example, oxygen in coal is readily converted to water or carbon dioxide. The formation of water is a cost consideration in liquefaction, because expensive

Figure 3.1
Typical Hydrogen-to-carbon Ratios by Weight
Canadian Fossil Fuels and Refined Products



SOURCE: G.W. Taylor, Liquid Fuels from Coal, 1979.

TABLE 3.1
IMPURITIES^a
(percent by weight)

	Moisture	Oxygen	Nitrogen	Sulphur	Mineral Matter
Lignite	28.0	16.8	1.1	0.7	6.5-34.0
Subbituminous Coal	20.0	16.0	1.4	0.6	15.0-22.0
High-Volatile Bituminous Coal	3.9-8.5	4.1	1.2	0.5-7.0	8.5-20.0
Athabasca Bitumen	<3.0	1.6	0.4	.4.5	0.6
Crude Oil	<0.1	<0.5	0.2	0.1-2.0	<0.1

SOURCE: G. W. Taylor, Liquid Fuels From Coal, Canada Centre for Mineral and Energy Technology, CANMET Report 79-13, Energy, Mines and Resources Canada, June 1979, p. 12.

^aTypical levels of impurities in Canadian fossil fuels (averages based on CANMET data). Premium liquid fuels such as gasoline, No. 2 fuel oil, and diesel fuel are virtually free of such impurities.

hydrogen is consumed in the process of converting coal to liquid products.

As coal contains more highly complex organic molecules and has a higher carbon to hydrogen ratio than petroleum, the goals of coal liquids conversion are basically twofold--to break down the complex molecular structure and to increase the hydrogen to carbon ratio. Relatively severe processing (the combination of high pressure, temperature and residence time) is needed to break down the complex coal molecule into smaller compounds. Large amounts of hydrogen are required to increase the hydrogen to carbon ratio to levels more typical of liquid fuels and to react with impurities such as sulphur and nitrogen so that they can be removed more easily from the system as hydrogen compounds. Minerals composed of silicon, aluminum, iron, calcium, sodium, titanium and other elements are also present. These materials must also be removed to make a suitable clean liquid fuel.

There are several routes by which these chemical changes can be accomplished and their reactions have been known for many years. Depending on the process used, a range of gases and liquids can be produced and, if desired, these in turn can serve as feedstocks to produce other chemical products.

Producing liquid fuels from indigenous coal was a national defense project, as early as the late 1920s, in countries which were short of petroleum reserves. The war effort in Germany in the 1930s used two successful liquefaction processes; the Bergius process for directly hydrogenating coal to liquid fuels and the Fischer-Tropsch process for synthesizing liquid fuels from a mixture of hydrogen and carbon monoxide, both produced from coal. Liquid fuels from these processes provided most of Germany's liquid fuel requirements during the Second World War.

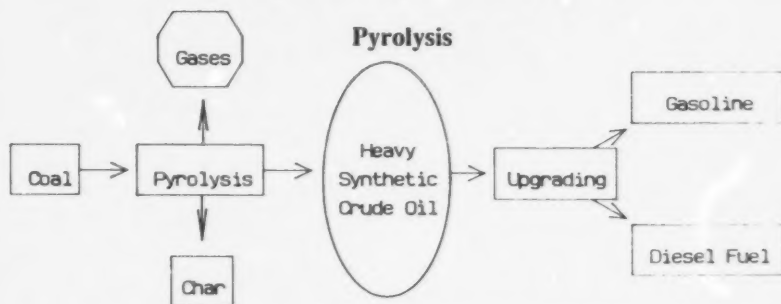
3.2 Process Routes

There are three major technical approaches to producing liquids from coal.¹ All three alter the basic nature of coal to produce liquid fuels or refining feedstocks (see Figure 3.2).

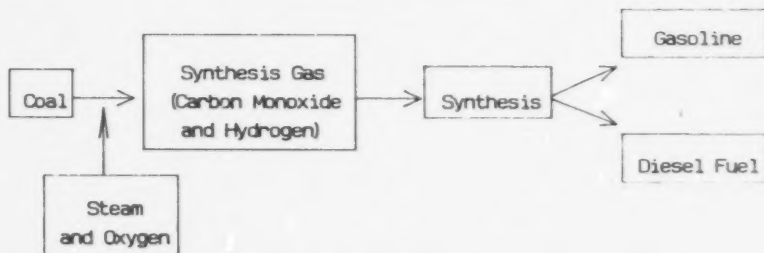
The three major methods of converting coal to liquids are:

- pyrolysis, which uses heat to drive off volatile matter, the liquid portion of which can be refined into usable

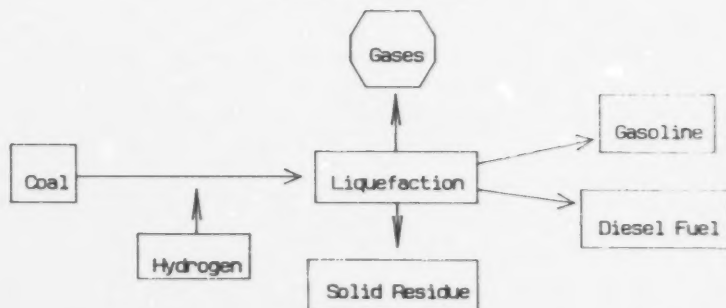
Figure 3.2
Coal Liquefaction - Process Schematics



Indirect Liquefaction



Direct Liquefaction



SOURCE: EIA, Future Transportation Fuels: Synthetic Fuels.

liquids leaving a carbon (char or coke) by-product. Pyrolysis is essentially a process which removes carbon rather than adding hydrogen;

- indirect liquefaction, in which coal is first gasified to produce carbon monoxide and hydrogen which are then reacted in the presence of special catalysts to produce liquid fuel; and
- direct liquefaction, in which the coal structure is partially broken down with the addition of hydrogen using a coal-derived solvent.²

The first approach, pyrolysis, is the simplest of the three processes. It yields char, a carbon-rich material, and heavy synthetic crude oil. Prior to the widespread use of natural gas, this process was used to produce combustible gases by heating coal in the absence of air. Volatile gases, called town gas, were driven from the coal and used for lighting, heating, and cooking. The main drawback with the pyrolysis process is the relatively low yield of liquids and large quantity of low value char production.

Indirect liquefaction is a two-step conversion process that first produces a gas mixture, which is then synthesized into liquids. Pioneered in Germany before World War II, this process is the one used at the only commercial coal conversion plants in the world, the SASOL (South African Coal, Oil, and Gas Co.) complexes in South Africa. In this process, coal is reacted at high temperatures with steam and oxygen to produce a mixture of gases, principally carbon monoxide and hydrogen. The synthesis of these gases using a catalyst produces liquid fuels. During the synthesis stage, the chemical bonds that were broken to produce the gases must be partially reassembled, making the process inherently inefficient. Indirect liquefaction does have the advantage of being able to use a wide range of coals or even biomass to produce high quality liquids. Liquid yields from indirect liquefaction are higher than from pyrolysis, but the fuel produced is extremely expensive.³

Direct liquefaction yields liquids directly from coal by the addition of hydrogen. Recently developed direct liquefaction (or hydroliquefaction) processes produce more liquid fuel with less carbon waste. Pulverized coal is reacted at high temperatures and pressures with the addition of hydrogen. Catalysts are also used and the choice of catalyst determines the efficiency of the process and, to some extent, the composition of the liquids produced. The drawback of

direct liquefaction is that the heavier hydrocarbons and other contaminants in the coal tend to deactivate the catalyst by carbon desposition leading to increased catalyst costs. However, hydroliquefaction yields are up to three times higher than those of either indirect liquefaction or pyrolysis and the liquids produced are of a higher quality than bitumen from oil sands or heavy oil.⁴

After refining, liquids produced from coal are similar to conventional fuels. The chemical composition of coal liquids is, however, such that they are less suitable substitutes for diesel fuel, a characteristic they share with synthetic crude oil produced from oil sands.

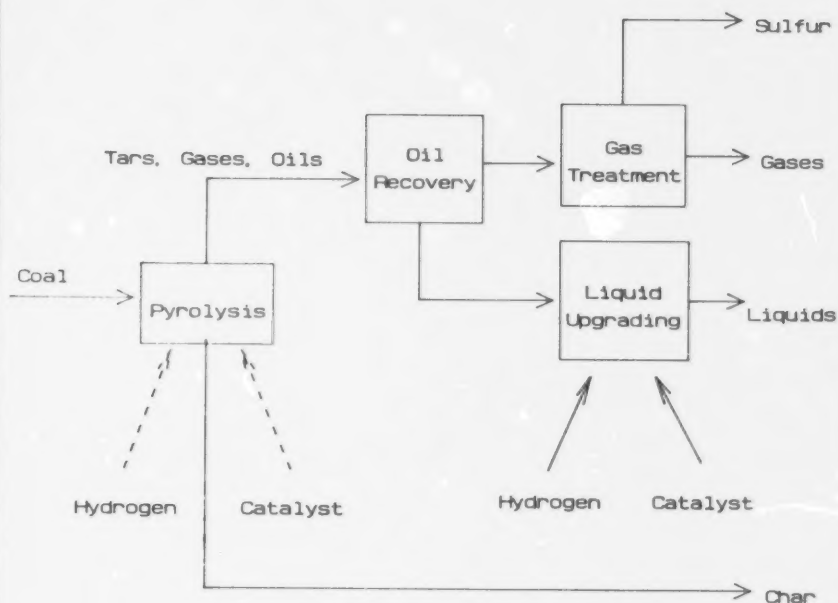
"Although synthesis is a commercially proven process in South Africa, it is economically less attractive mainly because of its inherently low thermal efficiency (35-50 percent) compared with pyrolysis (50-60 percent) and hydroliquefaction (60-70 percent)."^{5,6} This explains to a large degree why much of the coal conversion research undertaken in the last two decades has been aimed at improving the process economics of direct liquefaction or hydroliquefaction processes.

3.2.1 Pyrolysis

The least severe of the three liquefaction approaches is moderate to high temperature pyrolysis or coal carbonization (see Figure 3.3). Liquids, tars, and gases have been produced from coal pyrolysis since the late eighteenth century. Pyrolysis is simply a destructive distillation which generates volatile matter comprised of gases and condensable tarry material, and leaves a solid (char or coke) residue.

Heat is used to drive off or distill the volatile portions of the coal, but without the addition of hydrogen. In this process, coal is first crushed to the required particle size and heat is applied to produce water, gases and liquid hydrocarbons. A carbon-rich coke or char is left behind and hydrogen-rich tars, oil, and gases are released. The oil is recovered and sent to hydrogenation for upgrading to either fuel oil or synthetic crude. Gas is also recovered, scrubbed of contaminants and made available for use as a plant fuel, hydrogen plant feedstock or for sale as a by-product. The yields and properties of liquids and gases produced depend on the rank of the coal, maximum temperature and the rate of heating.

Figure 3.3
Pyrolysis/Hydropyrolysis



NOTE: The broken lines indicate that several options exist for the addition of hydrogen or catalyst in the primary stage.

SOURCE: M.P. du Plessis, Alberta Research Council, Coal Conversion Research Program at the Alberta Research Council, 1982.

Metallurgical coke for the blast furnace is made by pyrolysis. The tars and oils are used principally as petrochemical feedstocks, and the gas is burned to heat the coke ovens. Normally no hydrogen is used in the primary step and liquid yields are low, making the process unsuitable as a primary liquefaction process. Liquid yields can be improved if temperatures are lower, heating rates are faster, or hydrogen is added. Pyrolysis is also common in the petroleum refining industry, where it is more commonly called coking. It is used to recover light liquid products from heavy residual oils.⁷

Most processes based upon pyrolysis have been abandoned as means for producing liquids from coal because of their limited potential: the liquid yield (0.5 to 1.7 b/ton) is the lowest of the three liquefaction processes and some 70 percent of the coal remains as coke or char. Problems generally associated with pyrolytic processes include production of a large quantity of by-product char of uncertain usefulness or value, materials handling problems and consequent high production costs. Attempts to maximize yield have typically resulted in rather heavy tars which require expensive upgrading before qualifying as substitutes for liquid petroleum products.

Some research has been directed recently to the examination of whether a less severe pyrolysis process that produces light, higher quality liquids may result in more favourable economics, even though liquid yield would still be comparatively low. This new approach is referred to by various names: low-temperature or low-severity pyrolysis, mild pyrolysis, or differential liquefaction. The basic idea is to subject the coal to low-severity pyrolytic conditions of temperature and residence time to drive off the volatiles, which are quickly collected and condensed to avoid repolymerization reactions. The liquid yield is not very high, typically about a barrel per ton of feed coal, but the liquid has a very high quality as a heavy diesel fuel. While a great deal of char is left, it has been found to be suitable as a boiler fuel.⁸

Another approach is to heat the coal much more rapidly in the presence of hydrogen. This technique, termed flash hydrolysis, gives a char with improved burning properties, in addition to relatively higher liquid and gas yields. Since hydrogen is added, the process is a combination of hydroligneification and pyrolysis, and could be used to produce both liquids and a solid boiler fuel.⁹

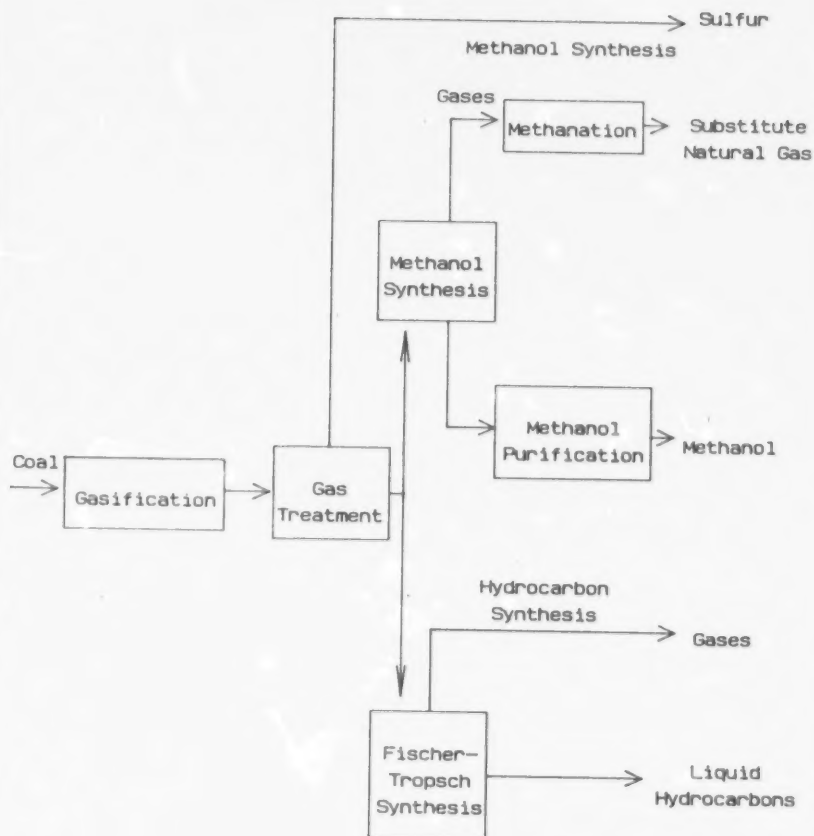
The electric utility industry has expressed some interest in pyrolysis and hydropyrolysis processing of coal, since the char can be utilized for its heat content either as a blend with coal in existing plants, or as the total feed in fluidized-bed plants or in boiler systems designed for use with low-volatile solid fuel. If the liquid pyrolysis product can be upgraded at a reasonable cost using modern petroleum refinery hydrogenation techniques and provided to an oil refinery as a feedstock, the char in effect would be valued at less than the cost of coal.¹⁰

In summary, interest in coal pyrolysis technology is fairly limited because of the inherently low yield of low quality liquids using currently available technology. While some progress has been made in the development of pyrolysis techniques, the basic yield pattern remains the same, with large amounts of low calorific value, high ash content char to be used or disposed of. There may be, however, specific applications where the volume and quality of the char by-product will be sufficiently high to offset the low liquid yield. Some interest in producing liquids by pyrolysis and hydropyrolysis of coal also stems from the fact that the equipment required is simpler to build and to operate than the equipment required in the total liquefaction processes. For these reasons, some limited R & D continues on pyrolysis processes.

3.2.2 Indirect Liquefaction

The first step in the indirect liquefaction processes is to produce a synthesis gas, consisting of carbon monoxide, hydrogen and smaller quantities of carbon dioxide and contaminants such as hydrogen sulphide, by reacting coal with oxygen and steam at 800°C or higher (see Figure 3.4). The liquid fuels are produced by cleaning the gas and adjusting the ratio of carbon monoxide to hydrogen in the gas. Syntheses are usually conducted over a suitable catalyst at temperatures between 250° and 450°C--depending on the type of synthesis. Depending on the catalyst, the principal product can be gasoline (as in the Fischer-Tropsch process) or methanol. The methanol can be used as a fuel or further reacted to produce gasoline, as in the Mobil methanol-to-gasoline process. The composition of the gasoline and the quantities of other products produced in the Fischer-Tropsch process can also be adjusted by varying the temperature and pressure at which the synthesis gas is reacted.

Figure 3.4
Synthesis



SOURCE: M.P. du Plessis, Alberta Research Council, Coal Conversion Research Program at the Alberta Research Council, 1982.

The indirect or synthesis process is thermally inefficient, but has an advantage in being able to use a wide variety of coals and produces high quality liquids. "This coal conversion route yields between 0.18 and 0.36 cubic metres of liquid per tonne (1-2 b/ton) but has the lowest thermal efficiency (35-50 percent) of the 3 options."¹¹

3.2.2.1 History of SASOL^{12,13}

Indirect liquefaction is presently the only process used on a commercial scale in the world, that being at the SASOL plants in South Africa. With large deposits of coal and no exploitable oil reserves, South Africa decided to base its energy regime on coal. While some development work related to this energy strategy was initiated as early as 1935, real progress did not occur until a state-backed company, the South African Coal, Oil, and Gas Corporation (SASOL), was established in 1950. Construction was initiated in 1952 on a coal liquefaction plant using both German fixed-bed and American fluidized-bed Fischer-Tropsch processes. In 1955, the SASOL I plant started operation in a new town, Sasolburg, located some 70 kilometres south of Johannesburg. The area was chosen for its abundance of coal, the availability of water, and close proximity to a market for its products. Between 1955 and 1960 considerable effort was spent overcoming technical problems in the fluidized-bed reactor. A completely new iron catalyst was developed and the process became known as the SASOL Synthol process which is today licensed by SASOL.

In subsequent years, various expansions and product diversifications were implemented. A pipeline was built to distribute gas to domestic and industrial consumers and an ammonia-based fertilizer complex was added, as well as a facility to produce butadiene, styrene and ethylene. By 1974, South Africa's original objective of establishing a synthetic fuels industry had grown and expanded to include a diversified petrochemical complex.

While the SASOL I project was eventually profitable, the construction of further plants was not economically justified because of the then stable and low price of oil, brought about by the exploitation of the huge Middle East oil fields. In 1973, the price of oil increased dramatically and the Sasol II project was subsequently announced in December 1974; the plant came on stream in 1980. SASOL II is over twice as large as SASOL I and produces mainly gasoline and

diesel fuel using Lurgi coal gasification and the SASOL Synthol process.

As a result of the 1978 Iranian revolution and the ensuing uncertainty in world oil supply, proposals to build a third SASOL facility were approved in 1979. SASOL III is virtually identical to SASOL II and is located adjacent to it. Several advantages were gained by this decision. Use of the same construction labour and infrastructure minimized engineering design costs and the plants were interconnected to improve flexibility. The SASOL III project was designed, constructed and commissioned in 3.5 years.

Currently, SASOL markets more than 100 products and concentrates on import substitution. It has become a supplier of raw materials for many satellite industries, and has diversified downstream into the fertilizer and explosives market. The three SASOL plants together produce over 50 percent of the total liquid hydrocarbons of South Africa and employ some 33,000 workers.

The production of oil from coal is felt to be viable in South Africa because of the unique combination of four factors: (a) the absence of petroleum deposits; (b) the availability of low-cost coal near the main market (the Johannesburg area); (c) the high cost of transporting oil to Johannesburg, which is situated 400 miles from the coast at an altitude of 6000 feet; and (d) assured security of supply.

The technology and economic viability of converting coal to gaseous and liquid fuels has been progressively improved by SASOL since 1955, with improvements in coal mining techniques, increases in the capacity and on-line time of the coal gasification units, and hydrocarbon synthesis reactors. Improved process formulation has resulted in more active synthesis catalysts with higher selectivities to liquid fuels, and downstream catalytic processes have been improved to produce higher yields of higher quality diesel fuel.¹⁴

Although the SASOL technology is inefficient and expensive, it has proved well-suited to the available coal and conditions in South Africa. It is in its present form, generally believed to be so uneconomic for North American conditions that it does not warrant serious consideration. In the long run, process modifications and improvements and the ability to selectively produce certain types of chemicals and use high-ash coals may make SASOL-type technology suitable in certain regions of Canada.

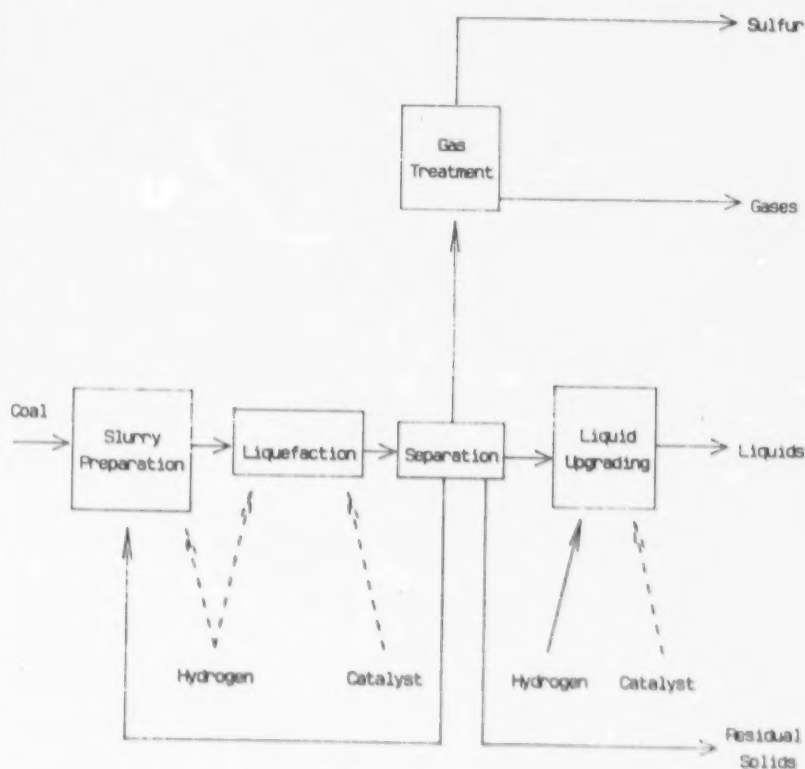
3.2.3 Direct Liquefaction

A destructive hydrogenation process patented by Frederick Bergius in 1913 was the forerunner of today's direct liquefaction technologies. Much of the liquid fuel used in Germany prior to and during the Second World War was produced by this method. In the latter days of the war, twelve Bergius hydrogenation plants were operating in Germany, with a total capacity of about 70,000 barrels of liquids per day, producing aviation gasoline from lignite, tar, pitch and hard coal. These plants were closed shortly after the war but there has been a large amount of research since then into revisions or refinements of the basic Bergius process, such as lowering the extreme reactor pressures required and improving the quality and amount of liquid that can be produced. While considerable research has been undertaken, direct liquefaction processes still remain at the pilot plant stage and have yet to be operated on a commercial scale (see Figure 3.5).

Direct liquefaction involves reacting coal in a slurry produced by mixing ground coal with a solvent which is itself a coal-derived liquid and is termed a recycle solvent. The liquefaction reactions proceed at elevated temperature to cause thermal decomposition of coal, high pressures to enhance incorporation of hydrogen in the coal material, and catalysts to promote and speed desirable hydro-cracking reactions, which sever the large coal molecular structure into smaller molecular groupings which are liquids. The addition of catalysts also acts to improve the removal of impurities such as sulphur, nitrogen and oxygen from the products. Hydrogen is either added directly to the mixture or donated by a hydrogen-rich solvent to yield a liquid product which in turn is distilled to produce a variety of fuels. The choice of catalyst determines to some extent the liquids produced by this process.

The various proprietary direct coal liquefaction processes are generally differentiated by their processing sequences and regimes of temperature, pressure, reaction time, solvent composition, catalysts, and reactor design. Differences also exist in the ability of the different processes to accept different types of coal, in the resulting products, and in the expected costs of operation. As a generalization, the major differences between the processes are the methods used to transfer the hydrogen to the coal, and the manner in which they use a catalyst, while maximizing catalyst life and avoiding the flow problems

Figure 3.5
Hydroliquefaction



NOTE: The broken lines indicate that several options exist for the addition of hydrogen or catalyst in the primary stage.

SOURCE: M.P. du Plessis, Alberta Research Council, Coal Conversion Research Program at the Alberta Research Council, 1982.

associated with bringing solid coal into contact with a solid catalyst.

There are basically three main contenders which are thought to be competitive in the medium term: H-Coal, Exxon Donor Solvent, and Solvent Refined Coal. Satisfactory conversion has been demonstrated in 30-250 t/day plants.¹⁵

The three major direct liquefaction processes are described briefly below.

H-Coal is a catalytic hydroliquefaction process developed by Hydrocarbon Research Inc. (HRI) for the conversion of coal to boiler fuels and synthetic crude oil. The H-Coal process is a novel application of the commercially proven ebullating-bed reactor, originally developed by HRI to convert heavy oil residue into lighter fractions. The process involves slurrying the feed coal with part of the product hydrocarbon and reacting it with hydrogen at about 800° to 875°F and about 3,000 pounds per square inch (psi) pressure in the presence of a cobalt molybdenum catalyst. It has been under development since 1963 and was successfully tested in a joint government and industry 250 ton/d pilot plant in Cattlesburg, Kentucky, from 1979 to 1982.

The Solvent-Refined Coal (SRC I) process was originally designed to convert high-sulphur, high-ash coals into low-sulphur and low-ash solid fuels. Modifications in the process resulted in SRC II, which produces primarily a liquid product. The SRC process bears similarity in concept to the Pott-Broche process developed in Germany in the 1920s. The coal is slurried with part of the liquid hydrocarbon product and reacted with hydrogen at about 850°F and a pressure of 2,000 psi.

The third major direct liquefaction method is the Exxon Donor Solvent (EDS) process, initiated by Exxon in 1966. In this process, coal and a hydrogenated process-derived recycle oil are reacted at about 800°F and 1,500 to 2,000 psi pressure. The solvent chemically donates hydrogen to the coal, and is then recycled for rehydrogenation. This process circumvents the problems of rapid catalyst deactivation and excessive hydrogen consumption. This concept was successfully tested in a 250 ton/d pilot plant at Baytown, Texas from 1980-1982 under a government and industry sponsored demonstration program.

In all three processes, the product is removed by distilling it from the slurry, so there is no residual oil fraction in these "syncrudes."¹⁶

It is important to note that the raw products of these three leading direct coal liquefaction processes are not retail liquid products. The raw distillable liquids still require considerable refinery-type hydrotreating to be converted to gasoline. Upgrading the raw coal-derived fuel oil involves relatively expensive refinery processing such as severe hydrotreating, hydrocracking or fluid catalytic cracking.

Direct liquefaction processes produce varying proportions of naphtha, which can often be blended directly with gasoline or used as a petrochemical feedstock, and distillates which can be treated to make diesel fuels and kerosene for transport and heating. Because of the chemical structure of coal, direct liquefaction processes yield products high in aromatics content. This makes them less suitable for diesel and jet fuels than the same products from crude oil. Refining the "syncrude" consists of further hydrogenation or coking (to increase hydrogen content and remove impurities), cracking and reforming.¹⁷ Current indications are that the most economically attractive product slate consists of gasoline blending stock and fuel oil.

The gasoline blending stock is high in aromatics, which makes it suitable for blending with lower octane gasoline to produce a high-octane gasoline. Indications are that with somewhat higher processing costs, coal-derived jet fuel can also be produced to meet all the refinery specifications for petroleum-derived jet fuel. However, since the methods used to characterize crude oils and the products of oil refining do not uniquely determine their chemical composition, the refined products from syncrudes will first have to be tested in various end uses to determine their compatibility with existing uses.¹⁸

None of the direct liquefaction processes has as yet been tested in a commercial-scale plant. All involve the handling of coal slurries, which are highly abrasive and have flow properties that cannot be predicted adequately given existing experience. Consequently, engineers cannot accurately predict the design requirements of a commercial-scale plant and the scale-up must go through several steps with probable process design changes at each step. Additional testing

and demonstration is required in order to reduce the risks associated with moving direct liquefaction processes to the commercial scale.¹⁹

The selection of coal feedstock, product slate and plant site is a complex one. The coal feed selection is the most important factor for direct coal liquefaction processes, since hydrogen consumption is a major cost component. Low-rank coals contain relatively large amounts of oxygen and therefore require larger amounts of hydrogen to liquify, as some hydrogen is spent in the production of water.

A number of direct liquefaction pilot plants have been in operation or are planned in Australia, Germany, the United Kingdom, the United States and Japan (see Appendix C). None of these pilot plants is self-contained and will require a full-scale operation to further test all aspects of the direct liquefaction chain. This next step is deemed essential as it would enable much better cost estimates to be obtained and would give greater confidence in assessing plant operability.²⁰

3.2.4 Comparison of Direct and Indirect Liquefaction Processes

Both the direct and the indirect process routes to liquid fuels from coal have particular processing advantages, and each is capable of producing a sufficiently broad product spectrum.

Direct liquefaction processes give rise naturally to products that range from hydrocarbon gases and light naphthas to heavy oils. Recent work has shown that coal-derived heavy distillates produced from several coals via a number of different processes can be upgraded in much that some fashion as conventional crudes. Likewise, SASOL has shown that the principal product from indirect liquefaction can be tailored to either gasoline or diesel fuels by altering the conditions of the synthesis reaction.

Processing advantages inherent in the direct liquefaction approach include the following:

- higher thermal efficiency than indirect processes;
- variable output of high octane gasoline and/or middle distillates; and

- physical conditions for direct liquefaction are relatively mild compared to the thermal conditions required for gasification.

Disadvantages often cited include:

- all processes require large quantities of hydrogen;
- handling of large quantities of slurries at high pressures has proven difficult; and
- separation of residual solids from the product stream can complicate processing, particularly if the feed coal is high in ash content.

As cited as early as 1982 in a report by the International Energy Agency (IEA), the only overriding disadvantage of direct liquefaction is that it has yet to be demonstrated on a sufficiently large scale to substantiate the positive claims made about it. The IEA notes that this demonstration step is essential, as plant reliability and operability of the complex series of individual process steps must be demonstrated and the performance of new full-size equipment established.²¹

Advantageous features of indirect processes include the following:

- product spectrum may be tailored to produce a wide variety of products by choice of catalysts and synthesis reaction conditions;
- because the synthesis gas feed can be made as "clean" as necessary to avoid catalyst deactivation, the use of exotic catalysts to improve yield is not precluded;
- the technology is already proven for gasoline production on a large scale; and
- more flexible gasifiers are under development which will make the process less dependent on coal type.

Disadvantages often cited include:

- lower thermal efficiency than for direct processes; and
- the difficulty of producing diesel fuels and kerosenes with current technology.

Most RD&D activity in IEA member countries since 1974 has focussed on direct liquefaction processes rather than the indirect synthesis processes. This has largely been because of the higher efficiency of these processes compared with Fischer-Tropsch synthesis, the widespread availability of suitable coals, and the ability to more easily tailor direct liquefaction technologies to produce a pre-selected slate of products.²²

Recent research has been aimed at making the following general improvements to the original direct liquefaction processes:

- improve hydrogen utilization, principally by reducing hydrocarbon gas production;
- increase liquid (distillate) yields;
- improve product quality;²³ and
- lower capital costs through less severe operating conditions.

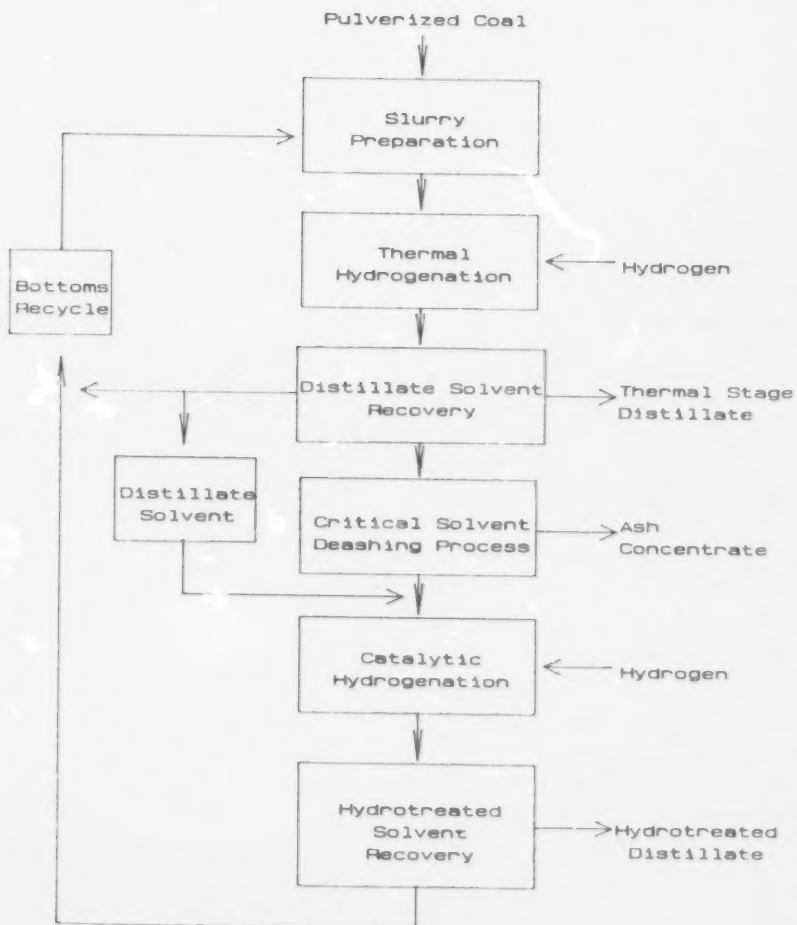
3.3 Recent Advances In Direct Liquefaction

3.3.1 Two-Stage Liquefaction

As noted in the preceding section, the direct liquefaction of coal is accomplished by breakdown of the complex molecular structure of coal in a slurry produced by mixing ground coal in a solvent, which is itself a coal-derived liquid. The liquefaction reactions proceed at elevated temperature and pressures; catalysts are used to promote and speed desirable hydrocracking reactions and also aid in removing impurities such as sulphur, nitrogen and oxygen from the products.

In an effort to lower capital costs, increase liquid yields and improve product quality, considerable research has been undertaken recently on ways to optimize the various process steps involved in direct coal liquefaction. These processes are generally termed two-stage direct liquefaction technologies, to distinguish them from the majority of first-generation processes which attempted to complete coal conversion in a single reactor. These two-stage processes feature a thermal first-stage liquefaction reactor followed by a catalytic second-stage reactor (see Figure 3.6).

Figure 3.6
Two-stage Liquefaction
(integrated mode)



SOURCE: EPRI, Integrated Two-stage Coal Liquefaction Steady State Performance, May 1985.

In the first stage, thermal decomposition of the coal occurs at one set of conditions followed by catalytic hydroprocessing of the primary liquids at another set of conditions more suited to upgrading these primary products into higher valued products. This second process is in many ways analogous to conventional refining of conventional crude oil.²⁴

Previous coal liquefaction processes attempted to solubilize and convert coal to liquid products in a single, high-temperature reactor. Because the optimum conditions for accomplishing these tasks differ widely, an inefficient use of hydrogen and lower yields of desired products than theoretically possible resulted, which in turn meant that further product upgrading was required. Two-stage processes use conditions that are better suited for coal conversion and have resulted in a substantial improvement in product quality and total liquid product yield, as well as reduced hydrogen requirements compared to single-stage predecessors.

Illustrative of recent refinements in direct liquefaction is the work that has been undertaken at the Wilsonville R & D Facility in Alabama. The Wilsonville R & D Facility combines three process units: a thermal hydrogenation or Thermal Liquefaction unit, a Critical Solvent Deashing unit, and a catalytic hydrogenation or Hydrotreater unit.²⁵ The combined three unit process system is generally referred to as the Integrated Two-Stage Liquefaction Process (ITSL). Integrated refers to the fact that at least part of the oil used in slurry preparation for feed to the first stage is derived from the second-stage reactor.

Two-stage coal liquefaction provides an opportunity to optimize the overall liquefaction process by carrying out the primary coal extraction step at one set of conditions and the catalytic hydrocracking of extract to distillate at another set of conditions. Significant improvements in the reduction in overall hydrogen consumption, light hydrocarbon gas make, and liquid yield have been found relative to single-stage processes.

"The Integrated Two-Stage Liquefaction process appears to make heavier coal liquids than either H-Coal or Exxon Donor Solvent (EDS), which may indicate a greater suitability to produce feedstock for high density transportation fuels."²⁶ Recent results indicate that

based on its low gravity, low paraffin content, and low distillation end point, the ITSL liquid would be favoured over those produced by the EDS and Solvent Refined Coal (SRC-II) processes.

3.3.2 Catalytic Two-Stage Liquefaction

Another version of a direct liquefaction process, Catalytic Two-Stage Liquefaction (CTSL), is under development by Hydrocarbon Research Inc. (HRI). This process features two direct-coupled ebullated-bed catalytic reactors in series. Improvements over other direct liquefaction processes have been noted in distillate yield, hydrogen utilization efficiency and catalyst activity maintenance. In addition, the HRI reactor is able to operate at lower temperatures than the ITSL thermal reactors.²⁷

In the CTSL process, coal is slurried with a process-derived recycle oil, mixed with hydrogen, and fed to the low-temperature first-stage catalytic ebullated bed reactor. The key feature which distinguishes this from other single- or two-stage processes is the operation of this low temperature (about 750°F) first-stage liquefaction reactor which contains an effective hydrogenation catalyst. Here, coal is converted by dissolution in the recycle solvent at a slow rate, allowing the catalytic hydrogenation reactions important for solvent regeneration and liquefaction product stabilization to keep pace with the rate of coal conversion.

Products from the first-stage reactor flow to a closely-coupled second-stage catalytic ebullated-bed reactor. The second-stage reactor operates at a higher temperature than the first stage for hydroconversion to high-quality, clean distillate fuels. The second-stage temperature, however, is lower than the conventional single-stage catalytic process temperature of 840° - 850°F. In stage two, the remaining reactive coal, as well as preasphaltenes and asphaltenes are converted to distillate liquid products and heteroatom contents are further reduced. Both reactor stages use conventional ebullated-bed hydrogenation/hydroconversion catalysts.²⁸

Previous ITSL processes relied on generating a high quality recycle donor solvent at low temperatures. One primary drawback to this sequential approach is that donor solvents are depleted in the thermal reactor, so that the final "spent" solvent quality is much poorer than the inlet recycle solvent.

The CTSL process avoids these drawbacks by conducting liquefaction at a much slower rate in a low-temperature first stage. The first-stage conditions provide a very efficient hydrogenation atmosphere, so that hydrogen compounds in the solvent can be regenerated effectively and reused over and over again. Thus the solvent does not become "spent." Primary liquefaction products are also efficiently hydrogenated as they are formed, reducing the tendency for regressive reactions. The second stage then completes the coal conversion at slightly higher temperatures in the presence of a much higher relative concentration of high-quality solvent. Second-stage conditions are chosen to optimize coal and residuum conversion and heteroatom removal without approaching the high thermal severity at which dehydrogenation of first-stage products becomes significant.²⁹

A series of tests have been made with both Illinois No. 6 bituminous and Wyodak subbituminous coals with the CTSL process. For Illinois No. 6 coal, process results are compared in Table 3.2 for the three approaches: the single-stage H-Coal process, a conventional two-stage process (thermal first-stage) and CTSL.

The comparative advantages of CTSL are:

- higher distillate yields than in the single-stage H-Coal process and other liquefaction processes are obtained. Distillate yields of 4.3 barrels of distillate per ton of moisture ash free (MAF) coal have been achieved;
- a low rate of catalyst deactivation has been observed;
- a 50 percent reduction in by-product gas make and a 50 percent reduction in residuum yield have been realized versus the H-Coal process;
- the ratio of distillate yield to hydrogen consumption shows a 20 percent improvement in hydrogen efficiency over single-stage processing;
- an improved selectivity to mid-distillate boiling range products is realized; and
- more petroleum-like distillate liquids are produced by the CTSL process than from other direct liquefaction processes.³⁰

TABLE 3.2
COMPARISON OF HRI'S COAL LIQUEFACTION
PROCESS RESULTS, ILLINOIS NO. 6 COAL

	H-Coal	DC-TSL ^a	CTSL ^b
<u>Yields, % M.A.F. Coal^c</u>			
C ₁ -C ₃	11.3	7.7	6.6
C ₄ -390°F	22.3	20.5	18.2
390-650°F	20.5	23.7	32.6
650-975°F	8.2	16.3	16.4
975°F+ Residuum	27.1	21.5	12.6
Hydrogen Consumption	6.1	6.4	6.3
Coal Conversion, Weight % M.A.F.	93.7	93.6	94.8
975°F+ Conversion, Weight % M.A.F.	72.9	78.5	82.2
C ₄ -975°F, % M.A.F.	51.0	60.5	67.2
C ₄ -975°F, bbl/ton M.A.F.	3.3	3.9	4.2
Hydrogen Efficiency ^d	8.4	9.5	10.7
Relative Reactor Volume	1.0	2.0	2.0
Severity, STTU ^d	38	46	22

SOURCE: A. G. Comolli and J. B. McLean, "The Low Severity Catalytic Liquefaction of Illinois No. 6 and Wyodak Coals," Second Annual Pittsburgh Coal Conference, Pittsburgh, Pennsylvania, Sept. 16-20, 1985, p. 377.

^aDirect-Coupled Thermal-Catalytic Two-Stage Coal Liquefaction.
^bDemonstration Run.

M.A.F. = Moisture-Ash-Free.

^dHydrogen Efficiency = $\frac{\text{Weight \% C}_4\text{-975}^\circ\text{F Distillate}}{\text{Weight \% Hydrogen Consumed.}}$

^eSTTU = Standard Time Temperature Units.

These results translate into a higher hydrogen efficiency (mass of distillate produced per mass of hydrogen consumed) for the CTSL process than for either of the other two processes discussed. Some measurements of product characteristics indicate that the CTSL product has a more petroleum-like character than products from other direct liquefaction processes. This feature is expected to render CTSL product more responsive to upgrading (less downstream product upgrading should be required for the CTSL product).

3.3.3 The Status of Direct Coal Liquefaction

Robert Lumpkin of Amoco, in a recent presentation to a conference sponsored by the Alternate Fuels Council, gave an excellent overview of recent improvements in direct coal liquefaction (see Table 3.3):

Interest in direct liquefaction steadily decreased during the 1980s as the price of crude dropped ... A key factor behind this indifference has been the economics derived early in the decade that established the price of transportation fuels from coal at \$80/bbl or higher. But there has been a dramatic improvement in the technology since 1983, and the impact of that improvement hasn't been widely appreciated. Recently, Amoco Corporation had new designs and cost estimates prepared based on the improved technology. The results show a 60 percent decrease in the cost of liquids from coal, down to an equivalent of \$35/bbl for crude oil. This improvement demonstrates the effectiveness of a steady, long-term research effort ... Additional improvements have been identified that could make direct liquefaction an attractive source of alternative fuels if research continues. Funding for even a minimum level of research is in jeopardy and needs to be secured.³¹

Lumpkin noted that Amoco's participation, in the mid-1970s, in development of HRI's H-Coal process was based on two particularly promising means of reducing coal liquids costs: (1) process development unit runs had shown that low cost subbituminous coals could give conversions nearly as high as those of comparatively hydrogen-rich bituminous coals under the right conditions; and (2) research seemed to indicate that lower hydrogen consumption was possible by using two-stage coal liquefaction. Lumpkin asserted that there is still room to improve yields further.

TABLE 3.3
DIRECT COAL LIQUEFACTION PROCESS EVOLUTION

	1935 I.G. Farben	1945 Billingham	1980 H-Coal	1986 Wilsonville
Pressure, PSI	10,000	3,000	3,000	2,800
Maximum Temp., °F	900	870	850	825
Coal Conversion, % M.A.F.	-	94	94	94
Hydrogen Consumption, % M.A.F.	14	8	6	5.6
Yields, % M.A.F. Coal Feed				
Hydrocarbon Gases	30	25	11	7
Distillable Liquids	54	54	51	65

SOURCE: Robert E. Lumpkin, "Recent Progress In Direct Coal Liquefaction," paper presented at the Alternate Fuels Conference, San Francisco, April 9-10, 1987.

If all oxygen in the coal is rejected as carbon dioxide, and the sulfur and nitrogen are removed as hydrogen sulfide and ammonia, respectively, then the yield of gasoline can theoretically be increased about 25 percent ... A number of elements have contributed to these improvements. There has been a strong trend by most developers toward two or more reaction stages, in contrast to the earlier trend of trying to reduce capital cost by doing the whole job in a single stage. The gain in control over the chemical reactions more than balances the cost for the second stage.³²

Lumpkin also emphasized that the technology for direct coal liquefaction is now similar in many respects to processes for hydrogenating petroleum residues that have been commercialized in recent years.

The potential for breakthroughs in the cost for producing transportation fuels by direct coal liquefaction remains very high, providing that a steady research effort can be maintained. The Wilsonville technical staff recently estimated that it might be possible to reach a distillable liquid yield of between 80 and 85 percent of the MAF feed coal without basic changes to the existing process. Improvements of this magnitude could lower the cost of liquid fuels from coal to \$25/bbl, or another 20 percent or so over the next few years.³³

3.4 Coal/Oil Co-Processing

Coal/oil co-processing is a comparatively new approach to liquefaction which is conceptually similar to direct liquefaction processes that use process-derived oil to prepare a feed slurry of coal. In coal/oil co-processing, however, the feed consists of coal and, instead of a recycled solvent, an external petroleum residuum, heavy oil or bitumen.

Coal/oil co-processing is an upgrading technology that involves the simultaneous conversion of coal and heavy oil or bitumen to synthetic crude oil. Co-processing utilizes coal to increase distillate yields while eliminating the high recycle oil requirement of direct liquefaction. Some research has also indicated synergistic effects--higher yields are obtained by co-processing than would be the case if the heavy oil or coal were processed separately.

What led to coal/oil co-processing was that in the earlier single-stage coal liquefaction pilots, some 70 percent of the total

liquid product stream was recycled to slurry the raw coal. By replacing the recycle solvent with fresh oil, the capital equipment could be much more effectively used and the capital cost per unit of output reduced. While a synfuel plant which co-processed both coal and heavy oil or bitumen would have the same basic equipment and processing stages as a direct coal liquefaction plant or heavy oil upgrader, considerable research has shown that this technique can offer significant economic benefits compared to the direct liquefaction of coal. The bitumen aids in the extraction of oil from coal and also acts to transfer hydrogen into the coal products while benefitting the conversion of the bitumen itself to distillate fuels. This process synergy has been estimated by some researchers to add up to 5 percent to the yield one would otherwise expect in the individual upgrading of bitumen and direct liquefaction of coal. Figure 3.7 shows the essential differences between direct liquefaction and co-processing.

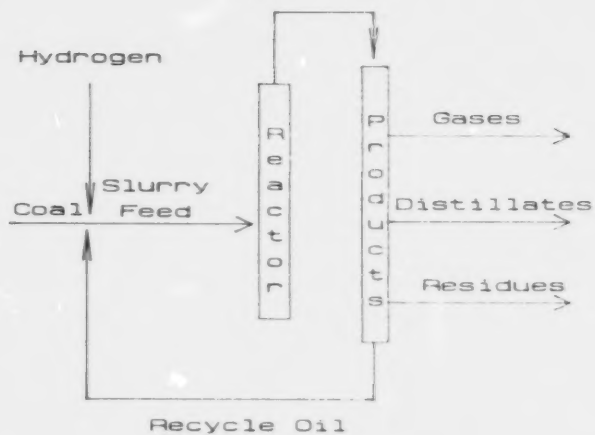
HRI, with funding from the U.S. Department of Energy, State of Ohio and Ohio Ontario Clean Fuels, Inc., is currently developing an advanced two-stage co-processing technique which is largely based on the improvements realized in catalytic two-stage direct coal liquefaction. In the two-stage coal/oil co-processing process, the crushed and prepared coal and petroleum residuum are mixed, pressurized, heated and, along with pressurized hydrogen, are introduced as a slurry to the first of two process reactors(see Figure 3.8).³⁴

In the reactor, hydrogen is added to the coal and heavy oil, and simultaneously hydrocracking generates lighter molecules. The hydrogen also reacts with the sulphur and nitrogen in the feed to form gaseous hydrogen sulfide and ammonia which are subsequently removed as waste products.

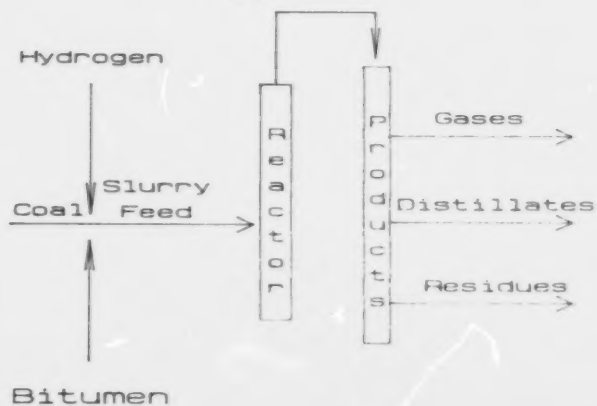
The efficiency of conversion and use of hydrogen is improved through the use of the second reactor. The liquid effluent from the second reactor is separated from the gases, and the lighter clean liquids are then collected through a series of pressure reduction and cooling steps. The heavy-liquid stream is cleaned and separated in several distillation steps and both the lighter and heavier liquids are further distilled and blended to produce clean naphtha and clean distillate. The gases are cleaned and separated into butane, propane and fuel gas.

Figure 3.7
Process Schematics:
Liquefaction and Co-processing

Liquefaction

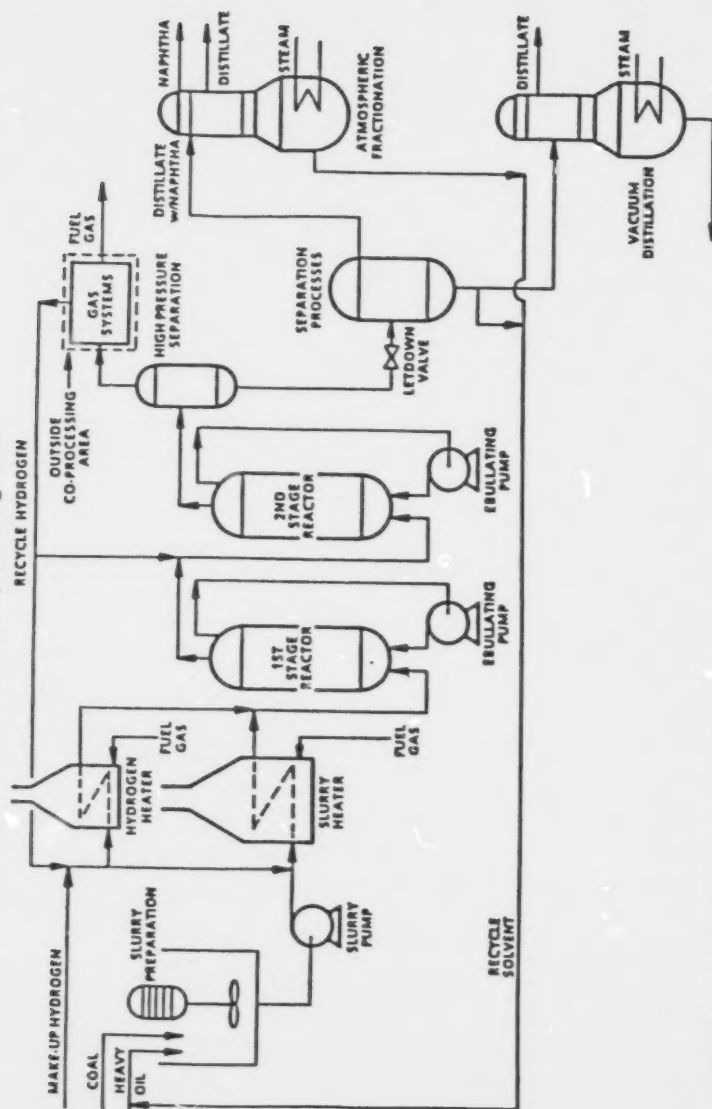


Co-processing



SOURCE: CANMET Co-processing - A Status Report, 1984.

Figure 3.8
Simplified Process Flow Diagram
Coal/Oil Co-processing Area



SOURCE: U.S. Department of Energy, Office of Fossil Energy, Comprehensive Report to Congress Clean Coal Technology Program, Prototype Commercial Coal/Oil Co-Processing Plant, October, 1987, p. 25.

During the gas cleanup, the water-soluble waste products are collected in a sour water stream which is then treated by conventional refinery processes to recover elemental sulphur and ammonia as by-products. The waste water is treated further for removal of organics before it is discharged from the plant.

The vacuum bottoms from the distillation process contain unreacted coal, ash, and residuum, which forms a solid material at ambient temperature. These bottoms can be solidified, flaked and burned to generate sufficient heat to satisfy the plant's steam requirements.³⁵

Some initial development work on coal/oil co-processing technology began when HRI started to develop their patented H-Coal process. Development of the H-Coal process using the ebullated-bed reactor to convert coal to liquids started some 20 years ago as the H-Oil process, which uses an ebullated-bed reactor to catalytically upgrade residual and heavy oils, moved toward commercialization.³⁶

Recent work has focused on a coal liquefaction process that uses a two-stage reaction. The two-stage process uses two ebullated-bed reactors connected in series, and results in higher product yields and better quality liquids. The use of two reactors also allows the process to operate at lower temperature and pressure, with concomitant capital cost savings. This work led to further refinement of co-processing technology which had previously used a single reactor to produce clean liquid fuels.

Although the co-processing of coal and petroleum residues essentially started with bench-scale tests about 20 years ago, most of this work was conducted as part of the H-Coal process development and was carried out to evaluate various solvents for that process. The first tests run specifically to process coal/oil mixtures took place in 1974 and effectively demonstrated the feasibility of coal/oil co-processing.³⁷

One clear advantage of the coal/oil co-processing approach to liquefaction is that greater throughput of product per unit of capital invested is realized. Although the feedstock cost is considerably higher than in direct coal liquefaction, due to the need to purchase the heavy oil or bitumen, the greater product revenues are typically

projected to more than compensate for the increase in feedstock costs. But while the hydrogen in the heavy oil dramatically reduces hydrogen consumption per unit of product, larger volumes of sulphur must be handled due to the significantly higher sulphur content of heavy oils and bitumen relative to coal.

In many ways, coal/oil co-processing is a natural bridge between heavy oil upgrading technology and direct coal liquefaction with recycle. Given a natural resistance to use major new technology, coal/oil co-processing offers a potentially significant advantage because it merges the process technologies of heavy oil upgrading and direct liquefaction of coal. The introduction of coal liquefaction in this manner could feasibly lead to major improvements in technology, as inexpensive feedstocks such as coal are optimized with improvements in more conventional processing techniques to upgrade Canada's increasingly heavy slate of crude oils.

Overall, coal/oil co-processing offers a number of advantages especially where coal, heavy oil/bitumen and natural gas are centrally located and available at reasonable cost. While these factors would generally support development in close proximity to the natural resource base, there are some situations where co-processing seems well-suited to consuming regions. Vacuum bottoms from conventional refinery operations can be combined with coal and natural gas at an adjacent co-processing plant to produce marketable boiler fuels, or to upgrade to light fuel oils. The use of existing petroleum refining facilities would mean that initial capital outlays to begin making synthetic fuels from coal would be much less than via the large liquefaction plants envisaged in the late 1970s. Recent developments in the United States supporting a prototype commercial coal/oil co-processing plant, together with ongoing evaluations of potential coal/oil co-processing applications in Alberta, Nova Scotia and Ontario, attest to the interest in and possibilities of this bridge-gap technology.

In many respects, coal/oil co-processing is an option which may be especially attractive to Canada, as it involves the simultaneous upgrading of bitumen or heavy oil and coal. The substantial endowment in Alberta of bitumen and coal, together with natural gas for hydrogen production, underscore the potential importance of coal/oil co-processing to future fuels development in Western Canada.

The benefits of coal/oil co-processing may be summarized as:

- reduced recycle solvent rates;
- reduced reactor and processing volumes;
- lower reaction pressures;
- lower reaction temperatures and improved thermal efficiency; and
- lower utility requirements.

These in turn support the potential economic attractiveness of the process:

- reduction in the capital cost of processing facilities compared to direct liquefaction;
- reduced capital for infrastructure modifications;
- reduced sensitivity to feedstock cost fluctuations through the ability to vary the oil-to-coal ratio;
- ability to operate at high liquid conversions without the need for expensive solids separation technology; and
- production of a high quality, high-value product.

3.5 Conclusions

Many variations of the three liquefaction routes--direct, pyrolytic and indirect--have been under investigation around the world, and the technology has advanced rapidly in the last decade. Research has concentrated on direct liquefaction in preference to pyrolysis and indirect processes, as being the most thermally efficient and potentially least expensive liquefaction route. The basic objective of this research has been to improve upon the original Bergius method by lowering the extreme reactor pressures required and improving the quality and amount of liquids produced.

The trend in process refinement in direct coal liquefaction has been towards milder operating conditions--lower pressure and temperature. The consumption of hydrogen has fallen considerably because fewer hydrocarbon gases are produced under the increasingly mild

operating conditions. Recent increases in the yield of distillate liquids without major penalties in hydrogen usage, together with less severe conditions, have meant a dramatic improvement in coal liquefaction economics relative to costs envisaged during the late 1970s. This improved technology has resulted in a 60 percent decrease in the cost of liquids from coal, down to an equivalent of \$35/bbl (\$U.S.) for crude oil. Additional improvements have been identified which could lower costs to \$25/bbl (\$U.S.).

While impressive gains in these areas have been obtained, most interest in coal liquefaction has waned in the face of the recent fall in oil prices. The interest that remains centers on coal/oil co-processing, an upgrading technology that involves the simultaneous conversion of coal and heavy oil or bitumen to synthetic crude oil. In coal/oil co-processing, throughput is maximized and yields are dramatically improved relative to direct coal liquefaction processes.

Although many of the components in the liquefaction process have been proven on a significant scale, there is great need to develop processes which are particularly suited to Canadian coals and siting opportunities (see Appendix C). Due to the differences in conversion characteristics across coals, the conversion of Canadian coals will require potentially significant "adoptive" research and demonstration programs. This is particularly true of Alberta subbituminous coals, which contain comparatively high levels of oxygen and ash.

Footnotes

¹A detailed and excellent description of existing liquefaction processes is contained in Robert A. Meyers, Editor in Chief, Handbook of Synfuels Technology, McGraw-Hill, New York, 1984.

Readers interested in an historical synopsis should see E. E. Donath, "Hydrogenation of Coal and Tar," Chapter 22 in Chemistry of Coal Utilization: Supplementary Volume, ed. H. H. Lowry, New York, John Wiley and Sons, 1963.

²Energy, Mines and Resources Canada. Future Transportation Fuels: Synthetic Fuels (Ottawa: Supply and Services Canada, 1987), p. 22.

³Ibid., p. 22.

⁴Ibid., p. 23.

⁵M. P. du Plessis, "Coal Conversion Research Program at the Alberta Research Council," The Journal of Canadian Petroleum, July-August 1982, p. 82.

⁶Thermal efficiency is the ratio of calorific values of total products to total feed coal in an energy self-sufficient commercial plant.

⁷G. W. Taylor, Liquid Fuels from Coal, Canada Centre for Mineral and Energy Technology, CANMET Report 79-13, Energy, Mines and Resources Canada, June 1979, p. 16.

⁸The Pace Consultants Inc., Synthetic Fuels Report. "Alternative Routes Compared for High Density Fuels From Coal," June 1987, p. 4-26.

⁹G. W. Taylor, Liquid Fuels From Coal, op. cit, p. 17.

¹⁰George R. Hill, "Pyrolysis Route For Coal Liquids Production," in Energy Technology Conference VIII, Washington: Government Institutes, Inc., p. 721.

¹¹Canada, House of Commons, Energy Alternatives. A Report by the Special Committee on Alternative Energy and Oil Substitution (Ottawa: Supply and Services Canada, 1981), p. 143.

¹²M. E. Dry and H. B. de W. Erasmus. "Update of the SASOL Synfuels Process," Annual Review of Energy, Volume 12, p. 1-21, 1987, p. 1-3.

¹³Some additional detail on SASOL is also presented in: S. S. Patel and T. D. Pay. "Foreign Coal Liquefaction Survey and Assessment" in Advances in Coal Utilization Technology IV, Symposium Paper, April 1981, p. 113 - 143; and Dr. D. F. Mostert, "SASOL's

Experience With the Coal Gasification Route to Liquid Fuels." Presented to the Sixth International Scientific Forum on Energy, October 29, 1982, Paris.

¹⁴Dry and Erasmus, op. cit., p. 21.

¹⁵Office of Technology Assessment, Congress of the United States. Alternatives for Reducing Oil Imports, Increased Automobile Fuel Efficiency and Synthetic Fuels, 1982, p. 164.

¹⁶Residual oil is the fraction that does not vaporize under distillation conditions. Since this syncrude is itself the by-product of distillation, all of the fractions vaporize under distillation conditions.

¹⁷At present, it is not clear whether existing refineries will be modified to accept coal syncrudes or whether refineries dedicated to this feedstock will be built. Local economics may dictate a combination of these two strategies. Refining difficulty is sometimes compared to that of refining sour Middle East crude when no high-sulphur residual fuel oil is produced (i.e., refining completely to middle distillates and gasoline). This is moderately difficult but well within current technical capabilities. One of the principal differences between refining syncrudes and natural crude oil, however, is the need to deal with different types of metallic impurities in the feedstock.

¹⁸The product is hydrogenated and cracked to form saturated single-ring compounds and saturated diolefins (which would tend to form char at high temperatures). The reforming step produces aromatics from the saturated rings. The rings can also be broken to form paraffins, but the resultant molecules and other paraffins in the "oil" are too small to have a high cetane rating (e.g., petroleum diesels generally have a cetane rating of 45 or more). Polymerization of the short chains into longer ones to produce a high-cetane diesel fuel is expected to be prohibitively expensive.

¹⁹Office of Technology Assessment, op. cit., p. 165.

²⁰International Energy Agency, Coal Liquefaction: A Technology Review. Organization For Economic Cooperation and Development, Paris, 1982, p. 15.

²¹Ibid., p. 16.

²²Ibid., p. 35.

²³Product quality refers principally to the ease with which the liquefaction product can be upgraded to end-use products. Boiling point distribution, hydrogen and heteroatom contents, and aromaticity all affect product quality.

²⁴National Coal Conversion Committee, Position Paper on Coal Liquefaction in Canada, prepared for Energy, Mines and Resources Canada, DSS Contract No. 03GR, 23218-3-0014, April 1985, p. 4.1.

²⁵Integrated Two-Stage Coal Liquefaction Steady-State Performance, The Advanced Coal Liquefaction R & D Facility, Willsonville, Alabama, prepared by Southern Company Services, Inc. Sponsored by the U.S. Department of Energy and the Electric Power Research Institute, Report Summary, May 1985.

²⁶The Pace Consultants Inc., Synthetic Fuels Report, June 1987, p. 4-25.

²⁷The Pace Consultants Inc., Synthetic Fuels Report, June 1985, p. 4.

²⁸A. G. Comolli and J. P. McLean, "The Low Severity Catalytic Liquefaction of Illinois No. 6 and Wyodak Coals," presented to Second Annual Pittsburgh Coal Conference, Pittsburgh, Pennsylvania, Sept. 16-20, 1985, p. 370.

²⁹*Ibid.*, p. 371.

³⁰*Ibid.*, p. 372.

³¹Robert E. Lumpkin, "Recent Progress in Direct Coal Liquefaction," Paper presented at the Alternate Fuels Conference, San Francisco, April 9, 10, 1987, p. 1.

³²*Ibid.*, p. 4.

³³*Ibid.*, p. 8.

³⁴U.S. Department of Energy. Office of Fossil Energy. Comprehensive Report to Congress Clean Coal Technology Program, Prototype Commercial Coal/Oil Co-Processing Plant. October, 1987, p. 3 DOE/FE-0092.

³⁵*Ibid.*, p. 4.

³⁶*Ibid.*, p. 19.

³⁷*Ibid.*, p. 20.

Chapter 4

RECENT ASSESSMENTS AND DEVELOPMENTS

This chapter opens with a description of a number of studies undertaken within the past several years of the potential role and economics of coal liquids technology in a Canadian setting, outlining the major conclusions and policy recommendations presented in these reports. The second component of the chapter presents the results of recent work conducted in the United States on coal/oil co-processing and direct coal liquefaction. A considerable amount of background detail is presented here and in Appendix D as the data from these U.S. reports formed the basis of the Institute's assessment of the comparative economics of coal liquids production which is presented in Chapter 5. Appendix C contains descriptive information on Canadian and foreign research and development.

4.1 Production Costs of Liquid Fuels From Coal and Oil Sands in Alberta

A study published in 1986 and undertaken by Dynawest Projects Ltd. on behalf of the Canada Centre for Mineral and Energy Technology, Energy, Mines and Resources Canada (CANMET), compared the production costs of liquid fuels from coal and from oil sands.^{1,2} The report was commissioned to provide a comparison of the production of liquid fuels from coal with the production of a product of similar specification by a current generation surface mined oil sands operation. The synthetic crude from each process had to be suitable as a refinery feedstock for the production of transportation and heating fuels.

Dynawest's first task was to decide which of the available liquefaction processes (direct or indirect) would be used for the comparison. As specified by CANMET, the choice had to conform to some specific criteria:

- advanced stage of development applicable at commercial scale in about 5 years;
- applicable to subbituminous coals;

- * minimum amount of uncertainty in estimating costs; and
- * produces major products that are equivalent in value to the synthetic crude from an oil sands plant.

The two criteria of advanced development and applicability to subbituminous coals narrowed available liquefaction processes very quickly.

The two major indirect routes were eliminated. The Fischer-Tropsch Sasol type process because of the large number of by-products, which resulted in a low conversion efficiency to liquid fuels. The Mobil MTG (methanol to gasoline) process, because it is a one product process and fails to meet the criterion of producing the potential range of liquid fuels that can be obtained from oil sands synthetic crude.³

Further evaluation of process technologies reduced the choice to the EDS (EXXON Donor Solvent) process and the HRI H-Coal process. These two were believed to have similar yields and economics and were felt to be at relatively comparable stages of development. Dynawest chose to use the H-Coal process as the basis for its comparison with an oil sands plant because:

- * previously published economics had always shown it as equal to or better than the EDS process;
- * the process is more easily adapted to give a particular product slate;
- * it has been demonstrated at the 200 ton per day scale with a coal similar to that which was selected for this study (Coal feedstock defined by CANMET was Picardville coal which is typical of Alberta plains subbituminous coal, see Table 4.1); and
- * there is sufficient published data on the process, particularly in relation to subbituminous coal, to allow a meaningful comparison with the current generation oil sands plant.

A scale of operations of 120,000 b/d (16 000 t/d) was chosen to make the operations comparable with an oil sands syncrude operation.

Dynawest's major conclusions were:

Within the constraints of this study and excluding infrastructure costs, we have estimated that the capital investment required for the coal based route exceeds that for the

TABLE 4.1
PICARDVILLE COAL DEPOSITS

Rank (ASTM):	Subbituminous C
Location:	40 km North of Edmonton
Reserves:	Strip mineable - 399 million tonnes Underground - 18 million tonnes
Mineability:	Typical plains conditions
Environmental:	Water supply adequate Good agricultural land
Infrastructure:	Rail, highways, towns and cities, clearly zoned
Typical Assay:	
Proximate:	Capacity Moisture - 29.3% Ash (as received) - 6.8% Fixed Carbon - 41.2% Caloric Value - 7 830 Btu/lb
Ultimate (MAF):	Carbon - 75.5% Hydrogen - 4.7% Nitrogen - 1.4% Oxygen - 17.9% Sulphur - 0.5%

SOURCE: Dynawest Projects Ltd., A Study to Evaluate and Compare the Production Costs of Liquid Fuels from Coal and from Oil Sands in Alberta, Final report, prepared for the Canada Centre for Mineral and Energy Technology, Energy, Mines, and Resources Canada, 1986, p. 14.

TABLE 4.2
CAPITAL AND ANNUAL OPERATING COSTS
 (millions of mid-1982 \$Cdn.)

	Oil Sands	Coal Liquefaction
<u>Capital</u>		
Direct Field Costs	2 767	3 331
Indirect Field Costs	1 878	1 986
Preproduction Costs	918	887
Post Start-Up Costs	180	-
Working Capital	102	198
Interest During Construction	1 500	1 669
Subtotal	<u>7 345</u>	<u>8 071</u>
Major Infrastructure Costs	963	-
Total	<u><u>8 308</u></u>	<u><u>8 071</u></u>
<u>Operating (per annum)</u>		
Wages and Salaries	257.0	324.4
Operating Materials, Chemicals	56.6	161.6
Maintenance Materials	89.7	152.9
Corporate Overhead	24.8	33.5
Property Tax and Insurance	40.0	56.2
Reclamation and Revegetation	6.0	5.5
Imported Power	3.9	15.9
Total	<u><u>478.0</u></u>	<u><u>750.0</u></u>

SOURCE: Dynawest Projects Ltd., A Study to Evaluate and Compare the Production Costs of Liquid Fuels from Coal and from Oil Sands in Alberta, Final report, prepared for the Canada Centre for Mineral and Energy Technology, Energy, Mines, and Resources Canada, 1986, p. 3.

oil sands process by approximately \$0.75 billion ... The major difference can be seen to lie in the primary ore treatment process which in the H-Coal process comprises multi-train coal preparation and liquefaction equipment costing about twice as much as its counterpart, the extraction and primary upgrading units, in the oil sands process.⁴

In respect to operating costs, Dynawest noted that the more sophisticated direct coal liquefaction technology would require a larger operating and maintenance staff and that it also has a higher demand for natural gas for power production and catalyst for the liquefaction reaction. Dynawest concluded that these together combine to give a higher annual operating cost for liquids from coal of about \$270 million (\$Cdn.) (see Table 4.2).

However, Dynawest observed that the straightforward cost penalty of the coal liquefaction process route was offset by a number of factors:

- the coal liquefaction process produces a higher proportion of the more valuable lighter petroleum fractions (see Table 4.3);
- the coal process has less environmental impact; and
- coal deposits are not located in such remote regions as oil sands deposits, thus the social impact of any coal-based project would be far less than that of an equivalent-sized oil sands project.

TABLE 4.3
MAJOR PRODUCTS AND BY-PRODUCTS
(kilotonnes/annum)

	Oil Sands	Coal Liquefaction
Naphtha	1 029	1 910
Distillate/Turbine Fuel	1 126	1 810
Gas Oil	2 675	1 110
LPG	110	0
Sulphur	280	50
Ammonia	0	173
Phenols	0	19

SOURCE: Dynawest Projects Ltd., *A Study to Evaluate and Compare the Production Costs of Liquid Fuels from Coal and from Oil Sands in Alberta*, Final report, Prepared for the Canada Centre for Mineral and Energy Technology, Energy, Mines, and Resources Canada, 1986, p. 4.

Dynawest also stressed that the higher capital cost of the coal liquefaction process is concentrated in the liquefaction reaction, and that it is exactly this part of the coal liquefaction process that is subject to the most intensive research and where costs can be expected to fall as development continues.

A list of some of the more important points presented in the Dynawest study are noted below.

4.1.1 Coal Conversion

At HRI's suggestion, Dynawest based much of its analysis on a 1979 study by Fluor for the U.S. Electric Power Research Institute (EPRI). The Fluor study examined two coal feedstocks, one of which, Wyodak subbituminous coal, is similar but not identical to the Alberta Picardville coal chosen as the basis of the Dynawest study. HRI noted that reaction conditions would probably have to be somewhat more severe for Picardville coal in order to obtain the same yields as for the Wyodak coal due in part to the lower hydrogen/carbon ratio of the Picardville coal.

No experimental work was undertaken by Dynawest to assess the differences in conversion properties of the two coals, owing to the substantial cost of experimental analyses. Given the lack of experimental work on the conversion properties of Alberta coals, Dynawest suggested that extensive experimental and design work would be required to clearly define and optimize the product yield from a coal liquefaction plant based on Picardville coal.⁵ Dynawest stated that the lack of information available on conversion properties led them to deliberately overestimate the hydrogen consumption required to produce products of equivalent value to the oil sands fractions.

4.1.2 Product Qualities

Dynawest observed that the most significant property of the coal-derived naphtha is its higher aromatics content and consequent higher octane number. This makes it an excellent reformer feedstock, easily reformed to high octane levels which is not the case for oil sands derived naphtha whose high paraffin content makes it extremely difficult to reform and necessitates blending with conventional naphthas to form an acceptable feedstock for existing refineries. However, while Dynawest concluded that the coal-derived naphtha is a more valuable material, it felt that the extent to which this would be

reflected in the market value of the material was uncertain and consequently made no allowance for this added-value in the economic assessment of coal liquefaction.

4.1.3 Environmental Impact

Dynawest reported that state-of-the-art technology is capable of reducing contaminants to levels well below the standards set by Alberta Environment. Responsible land reclamation and application of good pollution control technology would minimize the environmental impact of the coal liquefaction facility. Although the coal process, particularly the mine, would cover a larger area than the oil sands plant, the interval between initial mining and final reclamation would be shorter. Very importantly, at the conclusion of the project the mine would be completely revegetated; whereas, there is presently no known method for the reclamation of the tailings pond that would remain at the conclusion of oil sands projects.⁶ The authors also noted that emissions of sulphur dioxide would be significantly lower with the coal liquefaction process (less than one tonne/day compared to 150 tonnes/day from the oil sands plant).

4.1.4 Social Impact

Dynawest stated that the location of the Athabasca oil sands deposits dictates that new projects will require substantial investments in new service supplies and infrastructure such as power supplies, transportation systems, and accommodation. In contrast, a coal liquefaction facility located close to Edmonton (or any existing urban centre) would not require much of this expenditure. For this reason, the social impact of each new oil sands project must be considered more carefully than comparable investment in coal liquefaction facilities located near existing urban centres. Dynawest also added that the location of coal liquefaction facilities near existing centres would act to reduce some of the skilled manpower shortages and high turnover rates which have occurred at existing oil sands operations in the Fort McMurray area.

4.2 Economic Evaluation of Coal/Oil Co-processing

At the request of Alberta's Department of Energy and Natural Resources (AENR), HRI, the process licensor of H-Oil and H-Coal

processes, undertook an economic screening study of coal liquefaction, coal/oil co-processing and heavy oil upgrading at a remote site within Alberta.⁷ Depending on the case evaluated, unconverted residual material was supplemented by heavy oil, coal and natural gas to produce the steam required for the production of heavy oil via steam-drive techniques. This accounts to a large degree for the cost variance between this and other studies of coal liquefaction and coal/oil co-processing.

The report was completed in December, 1984 and an executive summary of the findings was made publically available by HRI. HRI's ebullated-bed reactor system was chosen for all the options evaluated because of its unique capability to process 100 percent heavy oil via the commercial H-Oil process, mixtures of heavy oil and coal via its COIL process, and 100 percent coal via its pilot plant-demonstrated H-Coal process.

In its summary report, HRI noted that co-processing, the simultaneous conversion of coal and oil to synthetic crude, offers many potential benefits, especially in a resource-rich area such as Alberta. Co-processing utilizes coal to increase syncrude production and eliminates the high recycle oil requirements of direct coal liquefaction, thereby reducing capital investment per unit of output. In addition, crude oil resources are extended and there is flexibility to vary coal/oil feedstock ratios according to their cost and availability.

HRI's COIL Process is a direct catalytic hydrogenation process for co-processing coal and oil in an ebullated-bed reactor. HRI has shown that the coal and resid conversions and liquid product yields from the COIL process can be greater than those expected by interpolation of H-Oil and H-Coal process performance. It is believed that this process synergy occurs because coal-derived liquids act as hydrogen donors for the oil feedstock, and enhance its conversion.⁸

Feedstocks evaluated in the HRI study were Lloydminster heavy crude and Alberta's Picardville subbituminous coal. H-Oil process yields for this study were based on HRI's extensive bench-scale and Process Development Unit (PDU) data for Lloydminster atmospheric residuum. Microautoclave testing was conducted as part of HRI's evaluation to determine the reactivity and suitability of the chosen feedstocks for coal liquefaction and co-processing. Conceptual plant designs were then developed for each case, using HRI's process planning

TABLE 4.4
DESCRIPTION OF CASES

-
1. H-Oil Process at Low Conversion--No Coal
Heavy crude is distilled with atmospheric resid going to H-Oil Process and the steam plant. H-Oil Process bottoms make up the balance of the fuel required for the steam plant.
 2. H-Oil Process at Low Conversion--With Coal
All atmospheric resid from the crude unit goes to the H-Oil Process. Steam plant fuel is coal and H-Oil Process bottoms.
 - 2a. H-Oil Process at Low Conversion--With Natural Gas
Same as Case 2, except coal to steam plant is replaced with natural gas.
 3. H-Oil Process at High Conversion--With Coal
Same as Case 2, except H-Oil Process is at high conversion.
 4. COIL Process Without Synergy
Coal is co-processed with atmospheric resid from crude unit. Steam plant fuels are coal and COIL Process bottoms. Yields are a direct interpolation of H-Oil and H-Coal Process data.
 5. COIL Process With Synergy
Same as Case 4, except increased conversion and liquid product yields are assumed.
 6. H-Coal Process
Syncrude produced entirely from coal via the H-Coal Process.
-

SOURCE: HRI, Inc., Economic Evaluation of Coal/Oil Co-processing: Executive Summary, Prepared for Alberta Energy and Natural Resources, Office of Coal Research and Technology, p. 2.

model to develop optimized commercial plant designs and economics. A description of the 7 cases evaluated in HRI's economic screening study is presented in Table 4.4.

Plant designs were based on the following assumptions:

- a nominal capacity of 20,000 barrels per stream day (BPSD) of syncrude product;
- a steam plant is provided at the upgrading plant site to generate the steam necessary for Lloydminster crude production via steam-drive techniques;
- unconverted residual material from the conversion process is utilized as steam plant fuel in all cases. This is supplemented by oil in Case 1, coal in Cases 2, 3, 4, and 5, and natural gas in Case 2A.
- natural gas is available to the upgrading plant as fuel and as feedstock for hydrogen production;
- electric power is purchased; and
- the economics were calculated on a basis provided by AENR, assuming no taxes or depreciation. The discounted cash flow analysis was based on the assumptions shown in Table 4.5.

TABLE 4.5
ECONOMIC BASIS

Debt/Equity Ratio	0/100
DCF Return on Investment	15%
Project Life	30 years
Constant Canadian Dollars	
Feedstock Prices:	
Lloydminster Crude	\$29.36/bbl
Picardville Coal	\$12.50/ton
- Fuel (Run of Mine)	\$25.00/ton
- Process (Cleaned)	
Natural Gas	\$ 1.42/Mcf

SOURCE: HRI, Inc., Economic Evaluation of Coal/Oil Co-processing
Executive Summary, Prepared for Alberta Energy and Natural Resources,
Office of Coal Research and Technology, p. 2.

4.2.1 Study Results

HRI concluded that the yield of syncrude per barrel of heavy crude feedstock increases directly with the use of coal.

In Case 1, where no other fuel is used, the yield is 0.63 barrels syncrude/barrel heavy crude (B/B). The yield of syncrude is increased to 0.90 B/B by using supplemental fuel (coal or natural gas) for steam production. Increasing resid conversion further increases syncrude yield to 1.02 B/B. The next step in coal utilization, direct co-processing, increases the syncrude yield to 1.13 to 1.19 B/B or almost twice the base case.⁹

Capital investments for the various cases evaluated by HRI were estimated based on 1983 Canadian dollars at an Alberta location and are shown in Figure 4.1. The constant dollar syncrude product costs required to achieve a 15 percent discounted cash flow are shown in Figure 4.2. Based on its analysis, HRI concluded that co-processing via the COIL process is essentially equivalent to the H-Oil process (Cases 4 and 5 vs. 2 and 3) and that coal liquefaction (Case 6) is more costly, primarily due to the much greater investment requirement.

The increase in syncrude yield provides the driving force for attractive economics for co-processing coal and oil. In the base case with no coal utilization (Case 1), the crude cost represents 60 percent of the total operating cost. With crude valued at \$175/t (\$29.36/B) and coal at \$25/t, there is incentive to replace crude with coal.¹⁰

The co-processing of coal and oil results in reduced crude costs relative to the H-Oil process, but this reduction is offset by other higher operating costs for coal, natural gas, labor, maintenance, and capital. The net result is that co-processing via the COIL process is cost equivalent to the H-Oil process but offers greater syncrude yields and feedstock flexibility. HRI noted that while direct liquefaction is relatively unattractive, primarily due to high investment costs, the comparison was feedstock-specific and other coals may provide significantly improved economics.

HRI summarized its conclusions as:

- * co-processing of coal and oil results in a low product cost of syncrude and greater feedstock flexibility;

Figure 4.1
Total Plant Investment

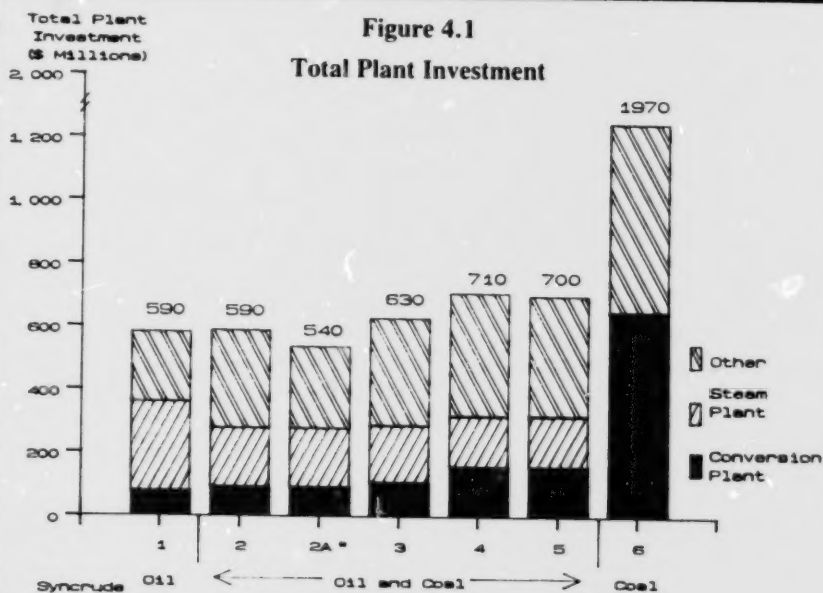
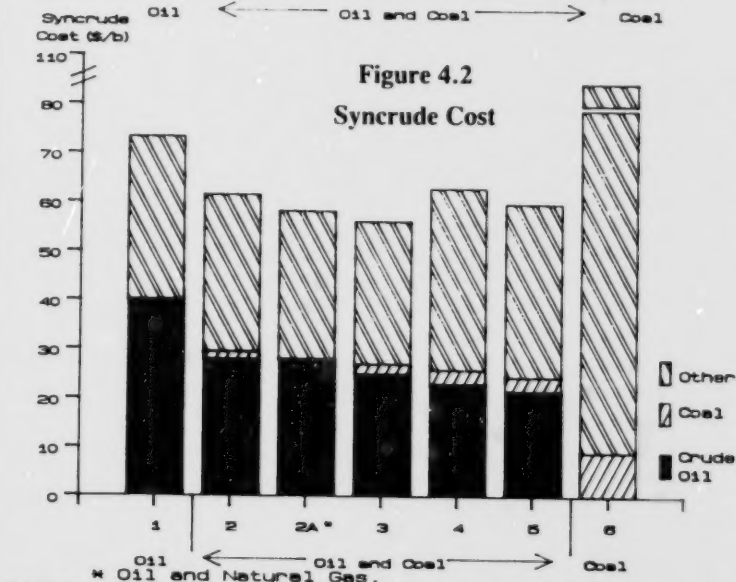


Figure 4.2
Synchrude Cost



* Oil and Natural Gas.
SOURCE: HRI, Inc. Economic Evaluation of Coal/Oil Co-processing: Executive Summary.

- direct coal liquefaction represents the highest product cost; and
- in order to confirm the assumptions and verify the results of this study, a bench-scale laboratory program followed by a preliminary commercial plant design is recommended for coal/oil co-processing technology.

4.3 Position Paper on Coal Liquefaction in Canada

In 1985, the National Coal Conversion Committee (NCCC) published a wide-ranging assessment of the potential role for coal liquefaction in Canada's energy future.¹¹ The authors of the NCCC position paper were comprised of representatives from coal-related interests in government, industry, and the research community. While the NCCC report concerned itself more with policy than economics, many of the arguments bring into focus a number of issues absent from other economic appraisals of coal-derived synthetic fuels.

The NCCC concluded that coal liquefaction and particularly co-processing has the potential for creating large new domestic and export markets for both Canadian low rank coals and natural gas and stressed that these processes should be actively demonstrated. A summary of their major findings is presented below.

4.3.1 Resource Base

The NCCC asserted that almost 60 percent of Canada's measured and indicated coal reserves are potentially suitable for liquefaction and that this resource base conservatively represents in the order of 150 billion barrels of oil.¹² Given the size of Canada's coal resource base, a concentrated effort to further understand coal properties and to develop the most appropriate and efficient methodology for conversion into liquid fuels is warranted.

Canada's abundant reserves of natural gas for the production of hydrogen necessary to upgrade coal to transportation fuels could provide secure and stable domestic markets for Canadian gas producers while producing light oil supplies.

The use of coal via coal/oil co-processing could extend, by more than a third, the total production of light fuels from the limited production of recoverable heavy oil/bitumen production.

4.3.2 Integrated Processing

The NCCC noted that coal conversion facilities could utilize existing infrastructure and transportation systems. Consequently, initial coal liquefaction plants could be constructed adjacent to existing coal mines, thermal power plants or refineries, resulting in minimal plant expenditures.

The close proximity of natural gas, heavy oil/bitumen and coal would also afford Western Canada unique opportunities in the upgrading and integrated processing of these resources for premium transportation fuels.

4.3.3 Product Qualities

The NCCC observed that coal liquids would be premium feedstocks for Canadian oil refineries as they have superior properties with respect to their ability to enhance gasoline octane ratings without the use of lead.

Studies conducted in Canada, the U.S.A., and West Germany have shown that coal-based synthetic fuels would command a higher price than some conventional petroleum crudes. This premium would be 10 percent, and perhaps as high as 20 percent, above the average price of petroleum crudes.¹³

4.3.4 Research and Development

The NCCC asserted that advances in technology indicate a potential for increasing yields to 4.2 and 4.8 barrel/MAF tonne for low rank and bituminous coals, respectively. These figures compare to yields in the late 1970s of 3.0 and 3.5 barrel/MAF tonne for these coals. Higher yields have resulted from process improvements related to two-stage processing, better catalysts and greater product recovery. This improvement in yield has also been achieved without corresponding increases in capital and operating costs which effectively translates to a 20 percent reduction in total unit cost.¹⁴

The NCCC noted that many aspects of direct coal liquefaction and coal/oil co-processing have already been proven at a commercial scale and the remaining technologies have been successfully demonstrated in pilot plant operations. Like Dynawest, the NCCC stressed that there is a great need to develop processes that are particularly

sulted to Canadian coals and siting opportunities.¹⁵ This is particularly true for Canada's subbituminous coals and lignites which, due to their high oxygen and ash content levels, require the application of special procedures in order to optimize the economics of their use as a source of liquid fuels.

4.3.5 Economic Issues

Coal/oil co-processing, as an alternative upgrading technology, is of particular interest as this option could reduce the need to export valuable natural gas condensates which are used as diluents to pipeline heavy oil and bitumen to American markets. Co-processing could displace imports of light crude oils, incorporate natural gas in the production of liquid fuels for export or domestic use, extend the production of crude oil from heavy oils, and create new domestic markets for Canadian coal.

Consequently, the co-processing mode of operation may prove to be the most attractive way of introducing coal into the production of synthetic fuels in Canada, particularly in Western Canada where the low cost of surface-mined coal as well as abundant natural gas for hydrogen generation represents a favourable situation.

Existing rail, road and pipeline systems in close proximity to coal resources would allow development of coal liquids plants to proceed without the extensive utility, transportation, and townsite development characterized by the more northerly surface-mined oil sands plants. Due to their location in the Arctic, East Coast Off-shore or Northern Alberta regions, many of Canada's other supply options will require substantial investment in support services such as townsites and transportation facilities. Conversely, the infrastructure to support coal/oil co-processing and coal liquefaction is to a large degree in place and the coal liquids option would, therefore, place fewer demands on direct public expenditures.

Unlike some of Canada's other supply options, the NCCC asserted that the scale of development for coal liquids production is suited to relatively small incremental steps of 10,000 to 20,000 b/d per processing plant.¹⁶ In addition, the NCCC noted that coal processing technology does not face the unforeseen risks associated with geological factors encountered in in-situ recovery of bitumen, enhanced heavy oil recovery and frontier development.

The NCCC concluded that the development route to coal liquefaction, either directly or through co-processing, presently receives a relatively small share of the incentives provided by Government to encourage private industry to undertake long-term developments in the national interest. The total investment by the private and public sector in coal synfuel development is accordingly out of proportion to the contribution that coal can make to the security of future oil supplies and the potential benefit to the economy.¹⁷

4.3.6 Comparative Process Economics

The NCCC briefly commented on Dynawest's evaluation of the comparative economics of synthetic liquids from oil sands and from coal liquefaction. It stated that Dynawest had substantially disadvantaged the coal liquefaction case as:

- the selected scale of operations of 120,000 b/d was an undesirably large scale for a coal liquefaction development;
- the plant site did not recognize the existing facilities and infrastructure in developed coal mining communities in Canada and the resultant capital savings;
- natural gas was not used for hydrogen generation;
- the cost advantages of modular or shop fabrication were not appraised;
- the shorter construction period and consequent lower working capital requirements for smaller scale coal liquefaction units were not recognized;
- technological advances which could give much greater oil yield per tonne of coal were not considered; and
- the capital cost to process the syncrude product to the same quality as the coal-derived product was not recognized.

The NCCC report noted, however, that the Dynawest study did conclude that the coal case would represent less land disruption and an earlier return to the original land use state, significantly less acid gas emissions, and lower overall water demand than a comparable-sized oil sands plant. The NCCC concluded:

After taking into account all these factors, this study supports the conclusion that coal liquefaction is at least equivalent and perhaps better than conventional surface mined oil sands projects. Had the study been conducted on a smaller, more practical, scale (40,000 bbls/day) the coal liquefaction case would have had a decided advantage.¹⁸

4.4 Co-Processing Initiatives In the United States

4.4.1 HRI Coal/Oil Co-Processing Program

In a paper presented in late 1986, HRI summarized the major results of its recent multi-client funded coal/oil co-processing program (Appendix D gives an overview of the U.S. coal/oil co-processing program). The paper also offered some updated economics of coal/oil co-processing relative to the direct liquefaction of coal. HRI's economic evaluation of direct coal liquefaction was prepared under contract to the United States Department of Energy (DOE) and compared conceptual plant designs and economics for both H-Coal and Catalytic Two-Stage Liquefaction (CTSL) based on the development of grass roots plants.^{19, 20}

Each design was based on providing a plant with four reaction trains, each processing 2,357 TPSD of Illinois No. 6 bituminous coal ... All facilities required for a complete grass roots plant were specified including coal handling and preparation facilities, liquefaction, hydrogen production via partial oxidation of liquefaction bottoms, product upgrading, all emission and effluent controls, utilities, and off-sites.²¹

Table 4.6 summarizes HRI's results and shows that coal/oil co-processing reduces the cost of liquid products from coal by almost half, from \$45.94/bbl to \$24.10/bbl (\$U.S.). HRI noted that the coal/oil co-processing study was based on a considerably smaller plant size than the direct coal liquefaction study and that the co-processing plant was assumed as an add-on to an existing petroleum refinery.

HRI concluded that the economic attractiveness of coal/oil co-processing was evidenced by:

- reduced capital costs of processing facilities;
- reduced capital cost for infrastructure modifications;

TABLE 4.6
ECONOMIC COMPARISON SUMMARY

Case	Coal/Oil Co-Processing	H-Coal
Weight % Coal in Fresh Feed	50	100
<u>Feedstocks</u>		
Coal, TPSD ^a	1,500	9,428
Oil, TPSD	1,500	-
BPSD ^a	8,371	-
<u>Liquid Products, BPSD</u>		
Naphtha	4,035	9,700
Distillate	10,174	16,078
Total	14,209	25,778
<u>By-Product</u>		
LPG, BPSD	-	4,144
Sulphur, TPSD	97	323
Ammonia, TPSD	22	107
Total Plant Investment, MM\$ ^b	261	1,738
<u>Product Cost^c</u>		
Operating Costs, MM\$/Yr	89	234
Capital Charges, MM\$/Yr	29	195
By-Product Revenue, MM\$/Yr	(5)	(38)
Product Cost, MM\$/Yr	113	391
\$/bbl (\$U.S.)	24.10	45.94

SOURCE: "HRI's Coal/Oil Co-Processing Program" by J. E. Duddy, J. B. MacArthur and J. B. McLean, Presented to Direct Liquefaction Contractors' Review Meeting, Monroeville, Pennsylvania, October 21-22, 1986, p. 17.

^aTPSD = tons per stream day; BPSD = barrels per stream day.

^b1984 total erected cost at a U.S. Gulf Coast location. Includes 25 percent project contingency.

^cFirst-year product cost based on 25 percent equity, 15 percent DCF return, 10 percent interest on debt, 5 percent annual inflation, coal @ \$30/ton and residuum @ \$15/bbl.

- production of a high-quality, high-value product;
- reduced sensitivity to feedstock cost fluctuation through the ability to vary the oil-to-coal ratio; and
- ability to operate at high conversions without need for expensive solids separation technology due to the low ash content of blended coal/oil feedstock.

The results developed from this coal/oil co-processing program culminated in the award of a DOE funding agreement for construction of a prototype commercial coal/oil co-processing plant.

4.4.2 Prototype Commercial Plant²²

In December 1985, the United States Congress made funds available for a Clean Coal Technology (CCT) Program (Public Law No. 99-190) and included approximately \$400 million to support the construction and operation of demonstration facilities using Clean Coal Technologies. The Clean Coal projects covered by the CCT Program encompass a broad spectrum of technologies having these common characteristics: (1) all are intended to increase the use of coal in an environmentally acceptable manner, and (2) all are ready to be proven at the demonstration level.

In response to the DOE program notice, fifty-one proposals were received in April 1986. After evaluation, nine projects, representing seven different technologies, were selected in July 1986 for funding under the CCT Program.

One of the nine projects selected was the Ohio Ontario Clean Fuels, Inc. (OOCF)²³ proposal to demonstrate technology for co-processing coal and oil to produce clean liquid products in a prototype commercial plant. These clean liquid fuels are to be produced from high-sulphur, high-nitrogen, Ohio bituminous coal and Cold Lake heavy crude oil. The project is intended to demonstrate the technical, environmental and economic advantages of co-processing coal and residuum oil versus utilization of these resources separately.

The following summarizes DOE's comprehensive program report to Congress and their evaluation of the risks and benefits of a prototype commercial coal/oil co-processing plant.

4.4.2.1 Project Description

The prototype demonstration plant is expected to start operation in 1991 and produce approximately 7,250 b/d of middle distillate and 4,500 b/d of naphtha for a total liquid fuel production of 11,750 b/d. Other products include approximately 340 b/d of propane, 190 b/d of butane, 185 tons per day (t/d) of flaked bottoms, 57 t/d of sulphur and 14 t/d of ammonia. The main feed materials for this facility will be 800 t/d of high-sulphur Ohio No.5/6 coal and 8,675 b/d of Cold Lake heavy crude oil (see Table 4.7).

It is proposed to operate the demonstration plant at the partially utilized site of a currently active steel distribution facility in Warren, Ohio serviced by oil and gas pipelines as well as by other important utilities.²⁴

4.4.2.2 Process Description

The demonstration project is a grass-roots plant, which necessarily means that it is a fully integrated process facility. Figure 4.3 displays a schematic for the ebullated-bed reactor used in the process; an overall block flow diagram of the proposed plant is shown in Figure 4.4 and a simplified process flow diagram of the co-processing plant is presented in Figure 4.5.

Co-processing starts by mixing prepared coal from the Coal Preparation Area (100), atmospheric bottoms from the Atmospheric Distillation Area (300), and a recycle solvent generated within the Co-Processing Area (200) in approximately equal parts in the slurry preparation tank. The mixture is then raised to pressure and transported by the special slurry pumps. The mixture flows through a gas-fired heater to raise its temperature and then on to the first of the two ebullated-bed reactors. This series arrangement of the two reaction vessels allows for operation at relatively mild conditions, as compared to earlier single-stage reaction schemes and attains higher yields and superior quality liquid products.²⁵

The hydrogen used in the process is first heated and then combined with the slurry mixture and injected into the reaction vessels. The reaction vessels contain a catalyst that is kept in an expanded or ebullated-bed state by circulating oil through it. The coal/oil slurry flows upward at a velocity that holds the catalyst in suspension. Hydrogen is also introduced into the bottom of the

TABLE 4.7
PROJECT SUMMARY

Project Summary

Project Title:	Prototype Commercial Coal/Oil Co-Processing Plant
Proposer:	Ohio Ontario Clean Fuels, Inc. (OOCF)
Project Location:	Warren, Ohio
Technology:	Co-Processing of Coal and Residuum Oil to Produce Clean Liquid Fuels
Applications:	Fuel for Utility or Industrial Boilers, Transportation, and/or Feedstock for Chemical Processes
Type of Coal Used:	Ohio Nos. 5 & 6 (High-Sulphur Bituminous)
Product:	Low-Sulphur, Low-Nitrogen Liquid Fuels
Project Size:	800 Tons Per Day Coal Feed, 8,675 Barrels Per Day Oil Feed, 11,750 Barrels Per Day of Clean Distillate Products.
Project Start Date:	October 1987
Project End Date:	December 1994

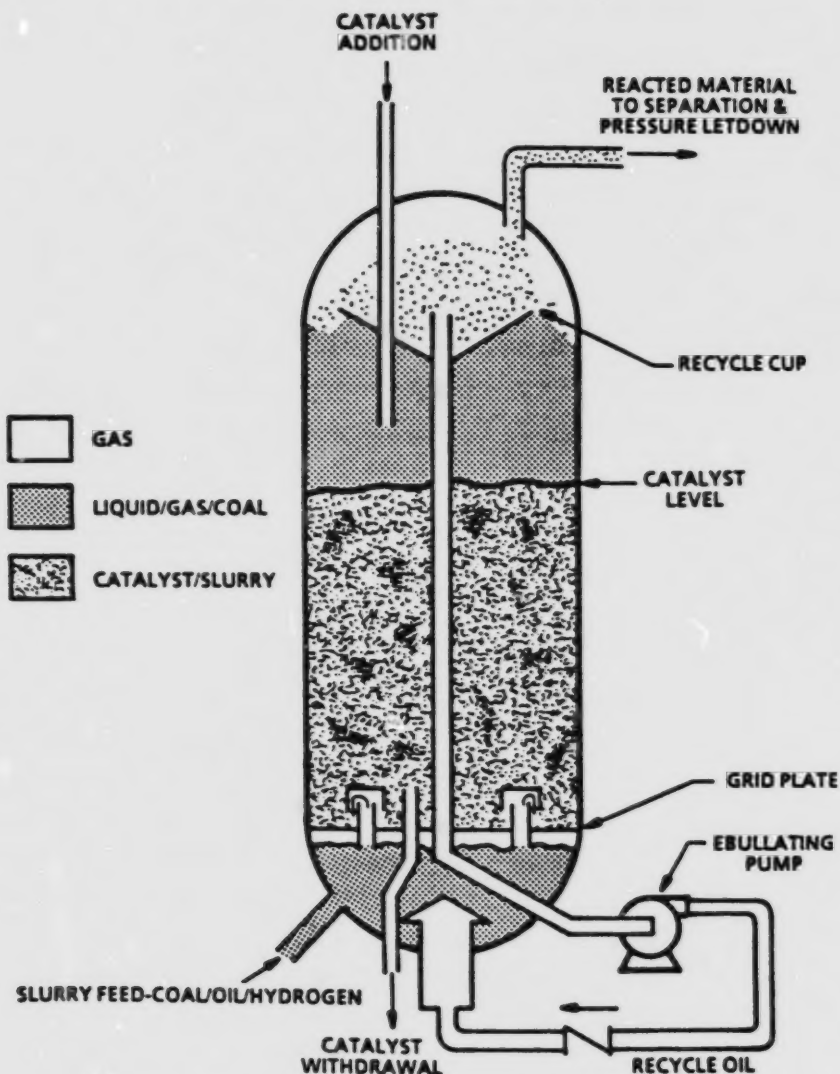
Project Sponsorship and Cost

Project Sponsor:	Ohio Ontario Clean Fuels, Inc.	
Co-Funders:	U.S. Department of Energy, State of Ohio, Stone and Webster Engineering Corp., Air Products and Chemicals, Inc., Canadian Occidental Petroleum Ltd., EPRI,* Equipment Vendors, and Merrill Lynch.	
Estimated Project Cost:	\$225,674,805	
Cost Distribution:	Participant Share (%)	DOE Share (%)
	80.1	19.9

SOURCE: United States Department of Energy, Office of Fossil Energy, Comprehensive Report to Congress Clean Coal Technology Program: Prototype Commercial Coal/Oil Co-Processing Plant, A Project proposal by Ohio Ontario Clean Fuels, Inc., October, 1987, p. 15.

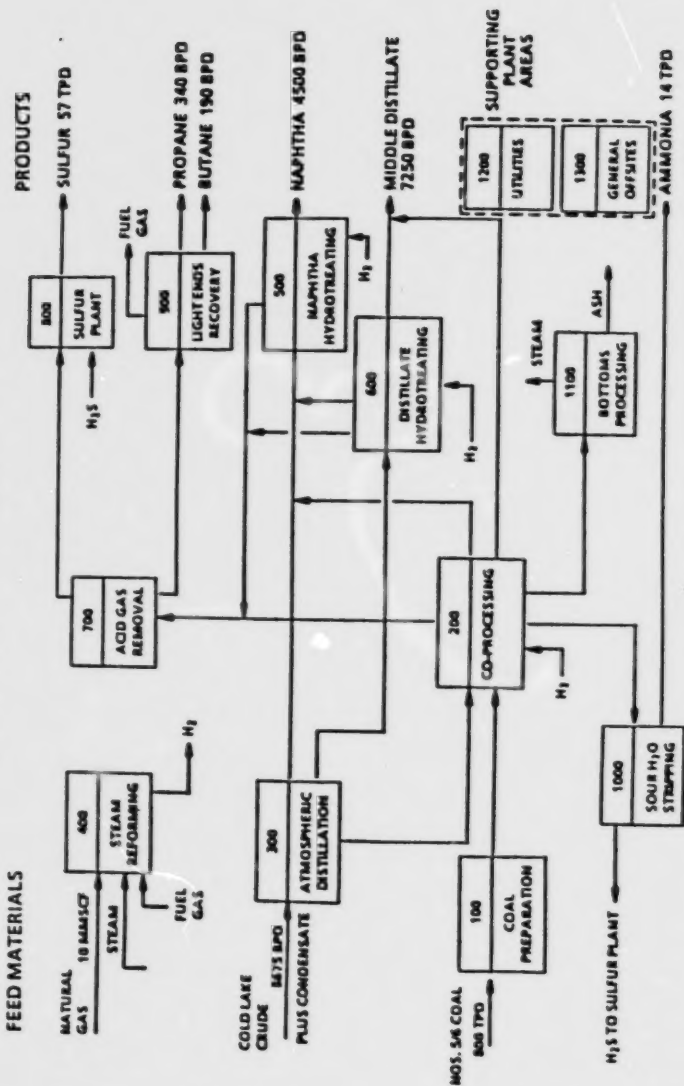
*The Electric Power Research Institute (EPRI) is providing funding support only for product combustion testing.

Figure 4.3
Reactor Schematic - Ebullated Bed



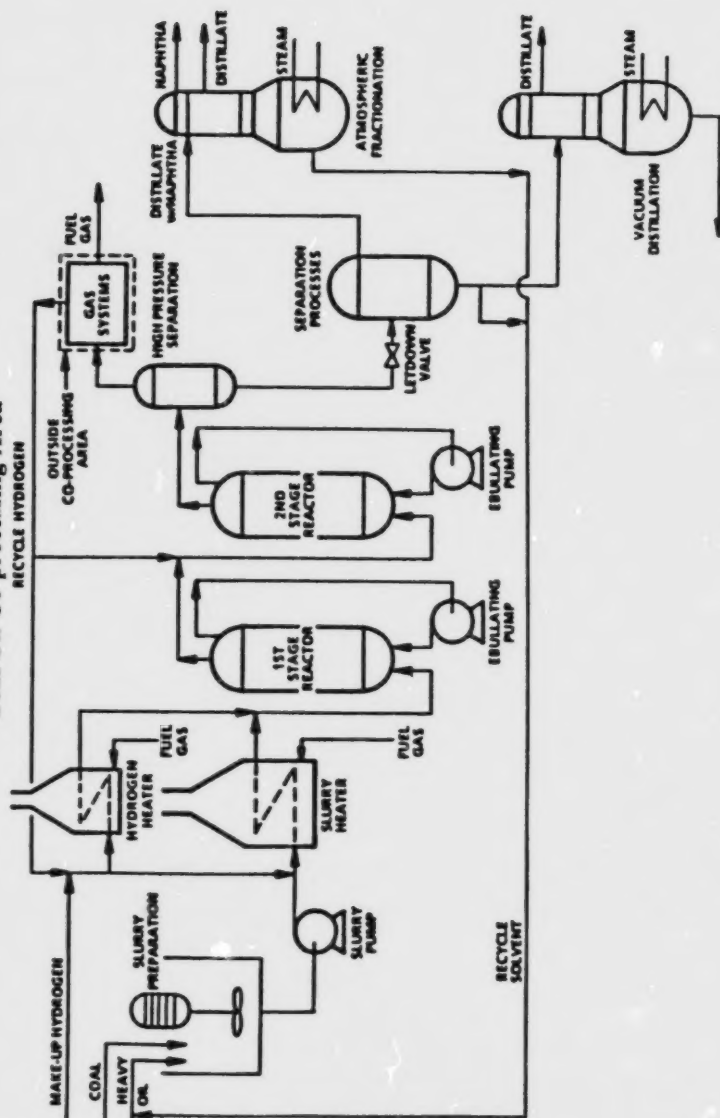
SOURCE: United States Department of Energy, Office of Fossil Energy, Comprehensive Report to Congress Clean Coal Technology Program: Prototype Commercial Coal/Oil Co-Processing Plant, A project proposed by Ohio Ontario Clean Fuels, Inc. October, 1987, p. 18.

FEED MATERIALS



SOURCE: United States Department of Energy, Office of Fossil Energy, Comprehensive Report to Congress Clean Coal Technology Program: Prototype Commercial Coal/Oil Co-Processing Plant. A project proposed by Ohio Ontario Coal Pioneers, Inc. October, 1987, p. 22.

Figure 4.5
Simplified Process Flow Diagram
Coal/Oil Co-processing Area



SOURCE: United States Department of Energy, Office of Fossil Energy, Comprehensive Report to Congress
Clean Coal Technology Program: Prototype Commercial Coal/Oil Co-Processing Plant, A project proposed by Ohio
Ontario Clean Fuels, Inc. October, 1987, p. 25.

reaction vessel with the slurry, and it too rises through the catalyst bed. The net effect is good contact between coal, hydrogen, catalyst and oil which promotes the hydrogenation of the coal and oil.

The partially hydrogenated coal/oil slurry then leaves the top of the first reaction vessel, is mixed with more hydrogen, and enters the bottom of the second ebullated-bed reactor used to complete the hydrogenation process.²⁶

The material leaving the second reactor is subjected to a series of process steps that lower the pressure, reduce the temperature, and separate the various reaction products. These raw products are separated into lighter liquid streams and a heavier solids-containing stream, which requires further and more controlled separation.

The co-processing system constitutes the central process section in this project. All ancillary processes utilized in the plant are well-established commercial operations and are included to provide support to the co-processing section by preparing the feedstocks; storing the feed, products, by-products and intermediate streams; upgrading or recovering the products and by-products; and processing the wastes from co-processing.

4.4.2.3 Developmental Risk

The DOE notes that while there is some element of risk, it is minimal as coal/oil co-processing is a combination of two more fully developed processes, H-Oil and H-Coal.

The H-Oil Process is a well-established, commercially proven, and active process. The H-Coal Process has been proven through pilot-plant operations. Both were developed through a reliance on the application of bench-scale and process development unit (PDU) data to design, build, and operate the larger units. Bench-scale work has been done for the co-processing process, and the results support the conclusion that co-processing is feasible on a commercial scale. An additional process development unit test will be carried out early in the project to confirm the basis of the project design activities and to generate sufficient quantities of products to conduct end-use studies. Therefore, it is believed that the technical risks associated with this project are resolvable with appropriate design and operating considerations.²⁷

The DOE recognized potential problem areas such as corrosion and erosion of equipment, coking at locations where heavy oil is subjected to high temperatures, and plugging and fouling of equipment used in the coal/oil processing areas. However, these are typical problems in process plants and normally remedied by special systems engineering, careful selection of construction materials and/or modification of operating procedures.²⁸

4.4.2.4 Technical and Economic Feasibility

The DOE considers coal/oil co-processing to be technically feasible as all ancillary sub-processes are well-established commercial operations that use conventional, commercially available equipment. The H-Oil Process has been licensed for use in the United States, Canada, Mexico, and several Middle East countries, and is a commercially proven and applied technology. Moreover, both the H-Oil Process and H-Coal Process were brought to their state of development based on the same type of bench-scale data that indicates co-processing is technically sound. There is, however, some risk in coupling the many separate processes into an integrated, smoothly operating and economic production plant.

A major objective of the CCT program is funding of clean coal technologies which appear to offer near-term commercial application. As such, a detailed monitoring program would be set up by DOE to ensure that the plant operates efficiently, safely, reliably, and economically in an environmentally acceptable manner. DOE's proposed monitoring program would include:

- determination of plant efficiency by monitoring each process area to ensure that it operates as designed;
- close monitoring of safety operations to ensure the safety of the demonstration project and the ability of future installations to operate safely;
- demonstration of the reliability of the process by placing priority on maintaining continuous operations; conditions leading to equipment outages will be identified and corrective actions implemented;
- a close monitoring and review of the economics, with emphasis placed on plant construction costs and feedstock and product prices, operating and maintenance costs; and

- the monitoring of emission and effluent control technologies to ensure their reliable operation in achieving compliance with environmental regulations.

DOE noted that the prospect of enhancing heavy oil upgrading at a number of existing refineries using low-cost coal was also an attractive feature of coal/oil co-processing technology. The prospects for commercialization are further enhanced as coal/oil co-processing fits very well into the existing coal and oil industry infrastructure. Coal and crude feedstocks can be readily obtained from the existing mining and transportation infrastructure and the products can be further refined and distributed through existing, idle, or underutilized refineries and petroleum product distribution systems.

In addition, the relatively small size of this project and its emphasis on modularization allow for better economics at a smaller scale when compared to direct liquefaction facilities. Studies have been completed that indicate that locating co-processing plants adjacent to existing refineries is an economically attractive option.²⁹

Finally, the technical performance of coal/oil co-processing is also an incentive for commercialization in that it can process relatively "dirty" fuels to produce very clean fuels and is relatively insensitive to feedstock composition, so that coal/oil ratios can be adjusted to take advantage of feedstock cost fluctuations.

In summary, the DOE noted that this technology's prospects for commercialization are enhanced by the following:

- reasonable plant capital and operating costs;
- compatibility with existing coal and oil industry infrastructures;
- production of high-quality products;
- recovery of sulphur and nitrogen as by-products;
- low sensitivity to feedstock cost fluctuations;
- increased ease of processing coal and heavy oil; and
- improved environmental performance of high-sulphur coal.³⁰

DOE concluded that the successful economic and technical demonstration of co-processing technology will result in a commercial process that can produce clean liquid fuels that meet or exceed existing product specifications and, at the same time, increase the use of coal and reduce oil imports.

4.5 Recent Advances in Direct Coal Liquefaction

Since 1979, the DOE has supported several research programs directed toward the development of multi-staged processing of coals to liquid fuels.³¹ The objective of these programs has been to produce a high yield of distillate fuels from coals of various ranks with efficient utilization of hydrogen. A number of promising two-stage process configurations have been developed at a Bench and Process Development Unit (PDU) scale by various contractors under DOE sponsorship. Those contracts include Lummus-Crest, Southern Company Services (Wilsonville), Hydrocarbon Research Inc., and Amoco.

The combined experience of several contractors has provided data for a variety of alternative two-stage liquefaction process conditions and configurations. As technical improvements may involve increases in capital cost, conventional measurements of technical performance such as product yield and hydrogen consumption are inadequate measures of process performance in a commercial context. Consequently, DOE requested the MITRE Corporation (MITRE) to undertake both a technical and economic comparison of recent advances in direct coal liquefaction processes.

The information presented below briefly summarizes MITRE's comprehensive technical and economic analysis published in June 1986. The objective of the study was to evaluate and compare the data in order to quantify the improvements made in the production of high quality distillates from coal and to identify promising research opportunities. The key tasks undertaken by MITRE were:

- review test data and select the most representative run for each process using both Illinois bituminous and Wyoming subbituminous coals;
- scale test data to develop material balances for conceptual commercial plants processing 30,000 tons per day of moisture free coal to the liquefaction units;

- identify unit operations for commercial plants;
- compute coal and energy requirements for plant balance;
- estimate capital and operating costs for commercial plants;
- compute annual revenue requirements based on consistent economic assumptions; and
- compute product costs required to satisfy revenue requirements.

Table 4.8 lists the two-stage processes evaluated. The MITRE analysis was also extended to include the H-Coal process developed by HRI and the Exxon Donor Solvent (EDS) systems, so that the degree of progress in two-stage configurations might be evaluated relative to representative single-stage liquefaction processes.

4.5.1 General Findings

Figure 4.6 shows the technical performances of Illinois No. 6 and Wyoming coals in various two-stage configurations. For the Illinois coal, total distillate yield varied from 50 weight percent moisture-free (MF) coal for the Lummus ITSL to 59 weight percent MF coal for the HRI CTSL process configuration. In the case of Wyoming subbituminous coal, distillate yield varied considerably from 39 weight percent MF coal for Lummus ITSL to 59 weight percent MF coal for the HRI CTSL process.

Table 4.9 summarizes the inputs and outputs for conceptual commercial-scale plants for both Illinois and Wyoming coals, processing 30,000 tons per day of dry coal to the liquefaction reactors.

The construction costs of the conceptual commercial plants were estimated using a 1981 commercial design of the Lummus Integrated Two-Stage Liquefaction (ITSL) plant as a basis for costs of unit operations. The annual revenue requirements for these plants were calculated on the capital recovery and operating costs developed based upon a consistent set of economic assumptions.

Figure 4.7 shows comparisons of the annual revenue requirement, equivalent product yield, and required selling prices of products from the conceptual commercial plants when operated with Illinois No. 6 bituminous coal. All values are shown as percentages of the Lummus

TABLE 4.8
TWO-STAGE PROCESSES

Process	Scale	Stage I	Deashing	Stage II
Lummus-Crest Integrated Two-Stage Liquefaction (ITSL)	600 Lb/Day	Thermal	Anti-Solvent	Catalytic
Wilsonville Two-Stage Liquefaction	3 T/Day	Thermal ^a	Critical Solvent Deashing	Catalytic
Hydrocarbon Research, Inc. Catalytic Two-Stage Liquefaction (CTSL)	50-100 Lb/Day	Catalytic	No Deashing Between Stages	Catalytic
AMOCO Thermal/Catalytic Two-Stage Liquefaction	50-100 Lb/Day	Thermal	No Deashing Between Stages	Catalytic

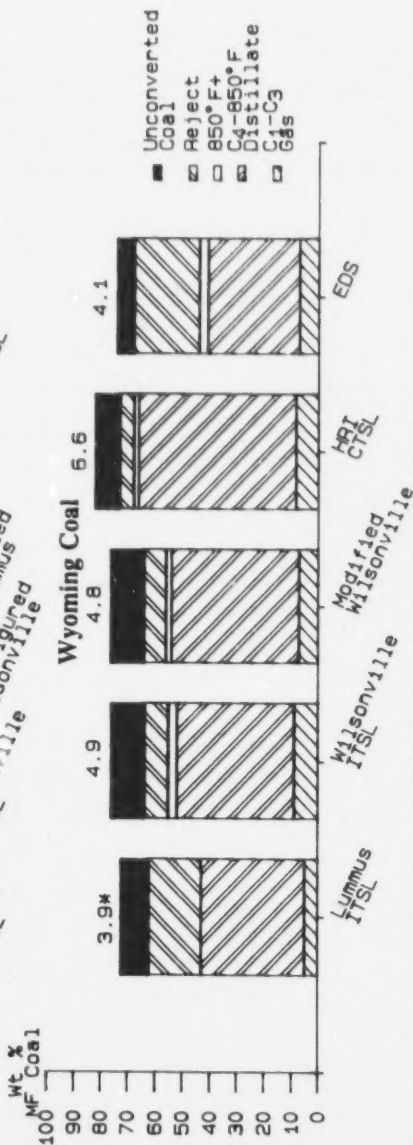
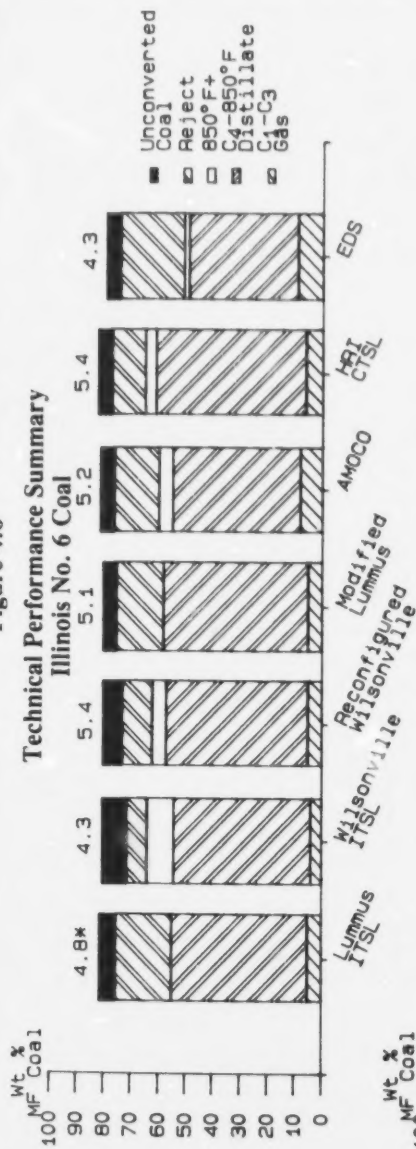
SOURCE: A. El Savy et al., The MITRE Corporation, A Techno-Economic Assessment of Recent Advances in Direct Coal Liquefaction, Prepared by Sandia National Laboratories for the United States Department of Energy under Contract DE-AC04-76DP00789-SANDS86-7103, June 1986, p. xiv.

^aSometimes slurry catalyst used.

Figure 4.6

Technical Performance Summary

Illinois No. 6 Coal



* numbers denote Hydrogen consumption in weight percent MF coal.

SOURCE: The MITRE Corporation, A Techno - Economic Assessment of Recent Advances in Direct Coal Liquefaction, June 1986, p. xv.

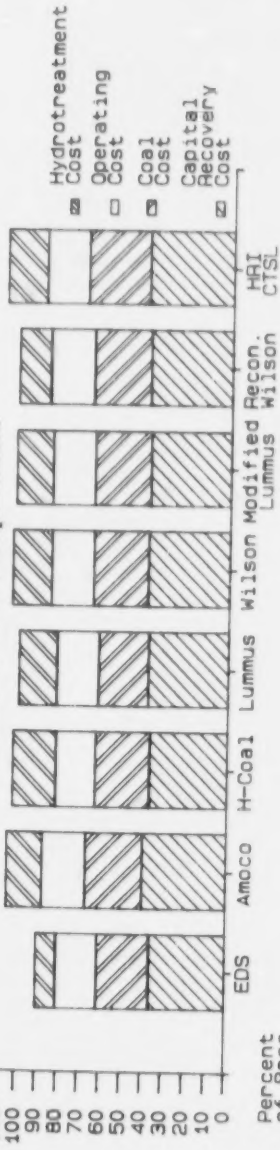
TABLE 4.9
CONCEPTUAL COMMERCIAL PLANT SUMMARIES

Process	Lumbee ITSL	Wilsonville ITSL	Wilsonville BITSL	Wilsonville DITSL	Modified Lumbee ITSL	Asarco	CTSL
<u>Illinois No. 6 Coal Feed</u>							
Input							
Steam Coal, TPD (NF)	2,000	1,700	2,300	-	2,500	2,600	2,500
Gasifier Coal, TPD (NF)	0	2,700	4,300	-	2,200	2,300	4,700
Total Plant Coal, TPD (NF)	32,000	36,400	36,600	-	34,700	34,900	37,200
Output							
SMC, MNSCFD	0	0	12	-	11	50	25
Raw C ⁴ + Liquid, BPSD	90,000	105,000	105,000	-	95,000	94,000	108,000
Total Liquid Yield after Hydrotreatment, BPSD	101,000	114,000	113,000	-	106,000	100,000	117,000
<u>Wyoming Coal Feed</u>							
Input							
Steam Coal, TPD (NF)	3,000	2,400	-	2,300	-	-	4,400
Gasifier Coal, TPD (NF)	0	3,400	-	3,700	-	-	8,800
Total Plant Coal, TPD (NF)	33,000	35,800	-	36,000	-	-	43,200
Output							
SMC, MNSCFD	33	28	-	6	-	-	3
Raw C ⁴ + Liquid, BPSD	70,000	90,000	-	97,000	-	-	114,000
Total Liquid Yield after Hydrotreatment, BPSD	80,000	94,000	-	98,000	-	-	119,000

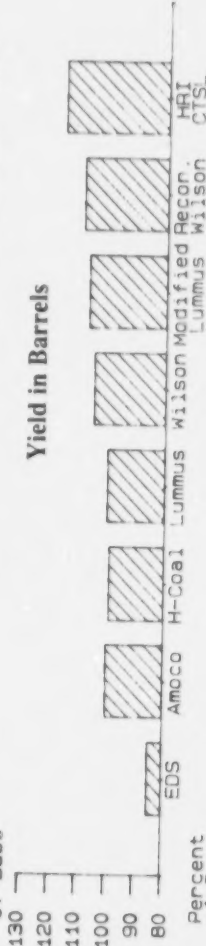
SOURCE: A. El Sawy et al., The MITRE Corporation, A Techno-Economic Assessment of Recent Advances in Direct Coal Liquefaction, prepared by Sandia National Laboratories for the United States Department of Energy under Contract DE-AC04-76NP00789-SAND566-7103, June 1986, p. xvi.

Figure 4.7

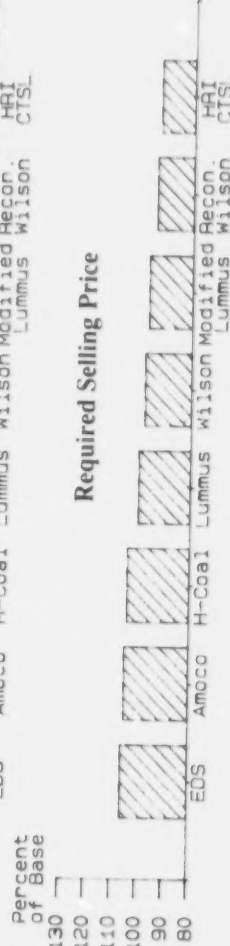
Economic Comparison - Illinois No. 6 Coal Annual Revenue Requirement



Yield in Barrels



Required Selling Price



SOURCE: The MITRE Corporation, A Techno-Economic Assessment of Recent Advances in Direct Coal Liquefaction, June 1986, p xviii.

Integrated Two-Stage Liquefaction (ITSL) process which was chosen as the base case. For comparison purposes, two conceptual plants based on single-stage processes (H-Coal and EDS) are also included.

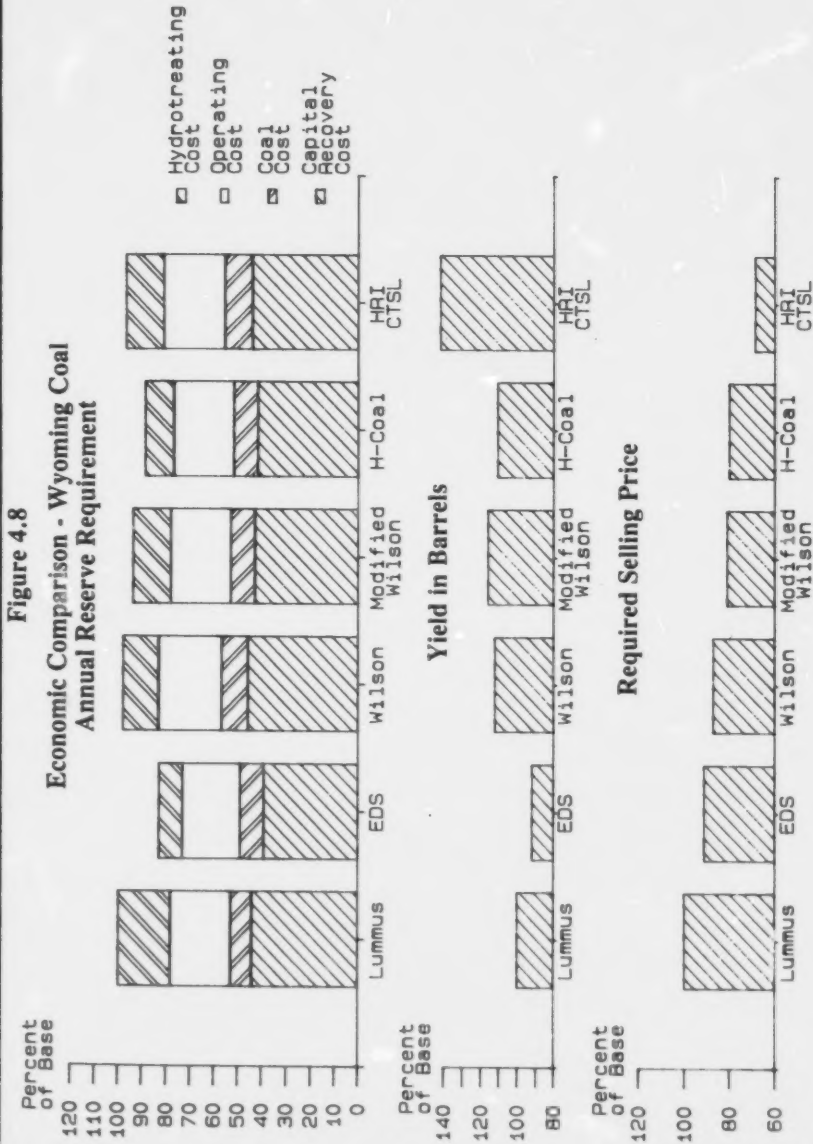
The bars depicting annual revenue requirements are divided into four sections illustrating the relative contribution of capital charges, coal, operating and hydrotreating costs. The total annual revenue requirements vary from a low of 90 percent of base for EDS to a high of 108 percent of base for CTSL. The equivalent barrels of yield indicates that EDS is the lowest at 85 percent of base, while CTSL is highest at 116 percent. The required selling price of hydrotreated products from the plants shows that prices vary from 106 percent of base for EDS to a low of 93 percent of base for CTSL; the most advanced systems (modified Lummus, Wilsonville RITSL, and CTSL) offer the lowest required products prices.

Figure 4.8 displays economic comparisons for conceptual plants operated with Wyoming subbituminous coal. The total revenue requirements vary from 94 to 100 percent of base for the two-stage plants, but are much lower at 89 and 83 percent of base for the single-stage H-Coal and EDS plants, respectively. Plant yields indicates a much greater variation than was observed in the plants processing the Illinois No. 6 coal; yields vary from a low of 92 percent of base for the EDS process to a high of 142 percent of base of the CTSL process. The required selling prices also show a wide variation. The Lummus ITSL shows the highest selling price at 100 percent of base, while CTSL offers the lowest price at 69 percent of base. The single-stage H-Coal and modified Wilsonville (DITSL), process offer similar prices of 80 and 81 percent of base, respectively.

4.5.1.1 Process Performance With Subbituminous Coals

As shown in Table 4.10, the HRI CTSL process produces substantially higher net liquid yields than the other two-stage systems. The two ebullated-bed catalytic reactors employed in CTSL upgrade virtually all of the soluble organic material to distillates.

The data from the processes again confirm that subbituminous coals are promising feedstocks for coal liquefaction. The subbituminous coals require more severe processing to achieve dissolution but achieve yields which are comparable on a MF coal basis to yields from bituminous coals. Products are



SOURCE: The MITRE Corporation, A Techno-Economic Assessment of Recent Advances in Direct Coal Liquefaction, June 1986, p. xx.

TABLE 4.10
TECHNICAL PERFORMANCE SUMMARY - WYOMING COAL

Process Conditions		Laramie ITSL	Wilsonville ITSL	Wilsonville DITSL	CTSL	H-Coal	EUS
Stage 1							
Temp., °F		840	810	825	750		840
Pressure, psia		2,000	2,405	2,425	2,500	833	2,000
HRT Hours ^a		.38	1.0	.71	1.33	.82	1.0
Stage 2							
Temp., °F		700	623	623	825	(NA)	(NA)
Pressure, psia		2,700	2,400	2,500	2,500		
HRT Hours		1.25	.55	.70	1.33		
Yield Structure, Wt. % NF Coal							
Heterogases							
C ₁ -C ₃		21.37	19.76	19.68	16.20	16.47	19.76
C ₄		5.39	8.34	6.96	7.50	9.41	6.84
C ₅ -C ₉		1.00	1.59	1.17	1.00	1.00	0.82
C ₁₀ -C ₁₅		1.15	17.61	20.11	16.68	25.69	17.47
380-650°F		36.51	17.98	22.72	29.78	15.03	13.34
650-850°F		0.64	7.30	4.30	9.77	1.75	3.17
850°F+		-	3.70	2.32	1.99	-	3.09
Belec ^b		18.75	8.77	7.56	4.67	18.72	22.87
LOH		10.08	10.60	11.01	10.03	9.35	7.70
Ash		9.00	9.00	9.00	9.00	9.00	9.00
Totals		103.89	104.85	104.83	106.62	106.42	104.06
Net Liquid Yield Wt. % NF Coal							
C ₄ -850°F		39.30	44.48	48.30	57.23	43.47	34.80
C ₄ -BP		39.30	46.18	50.62	59.22	43.47	37.89
C₄-850°F Product Properties, Weight Percent							
Carbon		88.62	83.75	84.66	87.70	87.30	85.41
Hydrogen		10.31	11.24	11.48	11.80	11.62	11.51
Oxygen		.83	2.27	3.05	.34	.70	2.86
Nitrogen		.20	.60	.77	.12	.32	.15
Sulphur		.04	.08	.04	.04	.06	.07
API ^c		15.60	24.90	28.00	28.50	29.05	32.60

SOURCE: A. El Savy et al., The MITRE Corporation, A Techno-Economic Assessment of Recent Advances in Direct Coal Liquefaction, 1986, p. 187.

^a Minimal Residence Time, assuming no gas holdup.

^b Belec = Benzene, Ethylbenzene, and Toluene.

^c API = American Petroleum Institute.

generally lower in boiling range and higher in hydrogen than products from Illinois No. 6 coal.³²

The important role of catalysts in processing subbituminous coals was also confirmed by the MITRE analysis--the processes which do not employ catalysts in the dissolution phase (EDS and Lummus ITSL) produce markedly lower yields than the other processes.

4.5.2 Commercial Plant Performance

The test results summarized in Table 4.10 were used to estimate process flows and outputs for conceptual commercial-scale plants processing 30,000 tons per day of moisture-free coal in the liquefaction sector. All plants gasify residual bottoms to produce hydrogen and additional coal is gasified if hydrogen produced from the bottoms is inadequate to meet process needs. Coal is also employed to satisfy plant steam requirements. Table 4.11 shows the characteristics of the commercial scale plants for Wyoming coals. Plants with high yields and/or high hydrogen consumption require large quantities of additional coal for steam and hydrogen production. As a result, the liquid yield per ton of coal to plant shows a smaller relative variation than liquid yields expressed in terms of weight percent MF coal liquefied.

In order to account for the differences in the quality of the liquid products from the various processes, MITRE calculated the hydrogen consumption and the volume gain occurring when the C₄-850°F output was hydrotreated to a heteroatom-free 35°API, 13-percent hydrogen product. The bottom two lines on Table 4.11 show the liquid yields in barrels/stream day and barrels/ton MF coal after hydrotreatment of the C₄-850°F fraction. For the Lummus ITSL process, liquid yields are considerably lower compared to the bituminous coals; however, for the other two-stage processes, liquid yields from both bituminous and subbituminous coals are similar.

Subbituminous coal appears to require more severe processing conditions, or at least first-stage processing in the presence of a catalyst for fairly long residence times. This is demonstrated by the far better results obtained using disposable catalysts as in the Wilsonville process, and commercial hydrotreating catalysts as in H-Coal and CTSL, compared to the thermal processing configurations of Lummus ITSL and EDS.³³

TABLE 4.11
CONCEPTUAL COMMERCIAL PLANT SUMMARY
WYOMING COAL FEED

	Laramie ITSLS	Wilsonville ITSLS	Wilsonville DITSLS	CTSL	H-Coal	EUS
Process:						
Coal to Liquefaction, TPD (NF)	30,000	30,000	30,000	30,000	30,000	30,000
Steam Coal, TPD (NF)	2,913	2,355	2,338	4,421	3,339	3,122
Gasifier Coal, TPD (NF)	0	3,456	3,674	8,842	1,899	0
Total Plant Coal, TPD (NF)	32,913	35,811	36,012	43,263	35,238	33,122
SHG, 10 ⁶ Btu/SD	33,288	28,596	6,096	3,228	54,384	60,816
Raw C ₄ Liquid, B/SD	69,981	89,974	96,889	113,946	84,723	74,009
Raw Liquid Yield, B/T (NF Coal)	2.13	2.51	2.69	2.63	2.40	2.23
Raw C ₄ -850°F Liquids, B/SD	69,981	84,208	93,273	110,846	84,723	69,193
Hydrotreated C ₄ -850°F Liquids, B/SD	80,366	88,001	94,344	115,801	87,558	68,617
Total Liquid Yield after Hydrotreatment, B/SD	80,366	93,767	97,960	118,901	87,558	73,433
B/Ton NF	2.44	2.62	2.72	2.75	2.48	2.22

SOURCE: A. El Sevy et al., The MITLE Corporation, A Techno-Economic Assessment of Recent Advances in Direct Coal Liquefaction, prepared by Sandia National Laboratories for the United States Department of Energy under Contract DE-AC04-76DP00789-SAN0386-7101, June 1986, p. 189.

4.5.3 Economics

Table 4.12 summarizes the economics for the conceptual plants using Wyodak subbituminous coal. Capital investment varies from \$3.6 to \$4.2 billion (\$U.S.); the hydrotreated product cost varies from approximately \$32 per barrel for the CTSL process to as high as \$46 per barrel for the Lummus ITSL case. On the basis of its analysis, MITRE concluded that the close-coupled, catalytic two-stage approach appears to be an excellent configuration for processing these inexpensive, low rank coal feedstocks. On average, capital charges account for approximately 52 percent of product cost, whereas the coal represents only about 12 percent. Without capital charges, good quality liquid products are possible from coal at a cost of approximately \$16 per barrel, when using low cost feedstocks such as Wyodak subbituminous coal.³⁴

MITRE concluded from its analysis that:

- solids removal after catalytic processing improves technical and economic performance; close-coupled liquefaction operations would appear to be the preferred approach;
- improvements in solids removal technology (deashing) would result in significant economic gains;
- western subbituminous coals are excellent feedstocks for catalytic two-stage processing; and
- catalysts play an essential role in the dissolution of Western subbituminous coals; the potential of disposable catalysts merits further investigation.

The overall conclusion from this analysis of both single and two-stage liquefaction of Illinois No. 6 and Wyoming coals indicates strongly that the additional costs and complexity of two-stage processing are justified by improved yield and product quality. In addition, the data from the processes confirm that subbituminous coals are promising feedstocks for coal liquefaction.

4.6 Conclusions

Over the course of the last several years, a number of analytical assessments have been conducted which point to dramatic technical advances in coal liquefaction technology relative to the late 1970s. Improvements in hydrogen efficiency and product yield have been

TABLE 4.12
WYOMING COAL PLANT - ECONOMICS SUMMARY
(millions of \$1981 U.S.)

	Lusk ITSL	Wilsonville ITSL	Wilsonville DITSL	CTSL	H-Coal	KUS
Plant Construction Cost	2,599	2,668	2,523	2,634	2,429	2,287
Total Capital Required	4,062	4,173	3,937	4,131	3,814	3,597
Annual Capital Recovery Cost	557	572	542	566	522	493
Coal Cost	124	135	136	159	133	125
Other Operating Cost	353	362	352	357	342	332
By-Product Credit	16	16	16	16	16	16
Hydrotreating Cost	246	183	172	165	144	119
<u>Raw Product Price Analysis</u>						
Eq. MB/SD Raw Product	72.8	89.5	95.6	112.7	89.3	76.7
Annual Revenue Requirement	1,018	1,053	1,014	1,066	991	934
Required Selling Price, \$/B	42.41	35.67	32.16	28.69	33.33	36.91
<u>Hydrotreated Product Price Analysis</u>						
Eq. MB/SD Hydrotreated Product	83.1	93.3	96.7	117.6	92.1	76.1
Annual Revenue Requirement	1,264	1,263	1,186	1,231	1,125	1,053
Required Selling Price, \$/B	46.10	40.15	37.20	31.75	37.03	41.93

SOURCE: A. El Sayy et al., The MITRE Corporation, A Techno-Economic Assessment of Recent Advances in Direct Coal Liquefaction, prepared by Sandia National Laboratories for the United States Department of Energy under Contract DE-AC04-76DP00789, SAND86-7103, June 1986, p. 190

realized together with reductions in processing severity required to produce coal-derived synthetic fuels. In addition, a move to two-stage processing in both direct liquefaction and coal/oil co-processing has resulted in further optimization of the complex series of steps involved in converting coal to synthetic fuels.

These technical improvements have resulted in a significant reduction in unit capital and operating costs. While direct liquefaction costs have fallen from the \$60-\$80 (\$U.S.) per barrel range to the \$32-\$46 (\$U.S.) level, costs of coal/oil co-processing stand at some \$24 (\$U.S.) per barrel. By all indications, coal/oil co-processing appears a near-term means for production of liquid fuels from coal. In addition to increasing domestic oil supply, it has the potential for creating new domestic markets for inexpensive, low rank subbituminous coals, natural gas and heavy oil/bitumen. Coal/oil co-processing facilities might also be located adjacent to existing infrastructure (coal mines, thermal power plants or refineries) to minimize plant expenditures.

Indicative of interest in the advancement of coal/oil co-processing are plans for construction and operation of a 12,000 b/d prototype commercial coal/oil co-processing plant in Warren, Ohio. The United States Department of Energy has agreed to underwrite the project by 20 percent in an effort to commercialize co-processing technology under the auspices of the U.S. Clean Coal Technology Program. Within Alberta, Canadian Energy Developments, Inc. has recently completed a detailed technical and financial analysis of a proposed coal/oil co-processing facility. The plant was assumed to begin operations in 1992 and produce 20,900 b/d of syncrude quality crude comparable to that presently produced by Suncor and Syncrude. In February, 1987 Ontario agreed to fund a 1-year feasibility study of a prototype coal/oil co-processing plant. The study's objective is to evaluate the construction and operation of a demonstration plant in the Sarnia area to produce in the order of 12,500 b/d of light synthetic crude oil from a mixture of Ohio coal and either bitumen from Alberta or heavy refinery residues (see Appendix C).

The MITRE analysis of recent advances in direct coal liquefaction processes confirmed that western subbituminous coals are excellent feedstocks for catalytic two-stage processing. Subbituminous coals appear to require more severe processing conditions to achieve dissolution but achieve yields which are comparable on a moisture-free coal basis to yields from bituminous coals.

The studies undertaken in Canada have all concluded that additional experimental research is required to prove the conversion properties of subbituminous and lignite coals, which have characteristics that require the application of special technologies owing to their high oxygen and ash content levels.

While the assessments presented in this chapter have described the rather dramatic improvement in economics due to recent technological advancements, they have generally tended to evaluate coal liquids technology in isolation. An economic evaluation of coal-derived synthetic fuels should not be undertaken in isolation but should rather be compared with other competing technologies under the same economic and market conditions. While coal liquefaction has advanced significantly, the issue that must be addressed is where does this technology stand relative to Canada's other crude oil supply options. The following chapter examines our assessment of this broader question.

Footnotes

¹Dynawest Projects Ltd., A Study to Evaluate and Compare the Production Costs of Liquid Fuels from Coal and from Oil Sands in Alberta, Final report, Prepared for the Canada Centre for Mineral and Energy Technology, Energy, Mines and Resources, Canada (Calgary: Dynawest Projects Ltd., 1986).

²The results of the comparison were first presented at the Proceedings of the Coal Liquefaction Contractor's Review Meeting, November 8-9, 1982, Ottawa, Paper 12, Andrew Hart, "A Comparison of the Technologies and Production Costs of Liquid Fuels from Coal and from Oil Sands in Alberta."

³Ibid., p. 3b2.

⁴Dynawest, 1986, op. cit., p. 1.

⁵Ibid., p. 83.

⁶Ibid., p. 86.

⁷HRI, Inc., Economic Evaluation of Coal/Oil Co-Processing: Executive Summary, Prepared for Alberta Energy and Natural Resources, Office of Coal Research and Technology, undated.

⁸Ibid., p. 2.

⁹Ibid., p. 3.

¹⁰Ibid., p. 3.

¹¹National Coal Conversion Committee, Position Paper on Coal Liquefaction in Canada, Prepared for Energy, Mines and Resources Canada, National Coal Conversion Committee, DSS Contract No. 03GR.23218-3-0014, April, 1985.

¹²Ibid., p. 5-5.

¹³Ibid., p. 6-7.

¹⁴Ibid., p. 6-12.

¹⁵Ibid., p. 4-7.

¹⁶Ibid., p. 6-1.

¹⁷Ibid., p. 1-4.

¹⁸Ibid., p. 6-2.

¹⁹Hydrocarbon Research, Inc., "HRI's Coal/Oil Co-Processing Program" by J. E. Duddy, J. B. MacArthur, and J. B. McLean, Paper presented to the Direct Liquefaction Contractors Review Meeting, Monroeville, Pennsylvania, October 21-22, 1986 published in HRI Coal/Oil Co-Processing Technology: Status Report, May, 1987.

²⁰Electric Power Research Institute. Coal-Oil Co-Processing: Phase I. AP-5101, Research Project 2657-1, Interim Report. Prepared by Hydrocarbon Research, Inc. for Electric Power Research Institute, Alberta Research Council and Ontario-Ohio Synthetic Fuels Corporation, Ltd., March 1987.

²¹Hydrocarbon Research, Inc., October 21-22, 1986, op. cit., p. 7.

²²United States Department of Energy, Office of Fossil Energy, Comprehensive Report to Congress Clean Coal Technology Program: Prototype Commercial Coal/Oil Co-Processing Plant, A project proposed by Ohio Ontario Clean Fuels, Inc. October, 1987.

²³Ohio Ontario Clean Fuels, Inc. is a wholly owned subsidiary of Ontario-Ohio Synthetic Fuels Corporation Ltd. of Toronto.

²⁴United States Department of Energy, October 1987, op. cit., p. 14.

²⁵Ibid., p. 24.

²⁶Ibid., p. 26.

²⁷Ibid., p. 32.

²⁸Ibid., p. 34.

²⁹Ibid., p. 40.

³⁰Ibid., p. 41.

³¹A. El Sawy et al., The MITRE Corporation, A Techno-Economic Assessment of Recent Advances in Direct Coal Liquefaction. Prepared by Sandia National Laboratories for the United States Department of Energy under Contract DE-AC04-76DP00789.SANDS86-7103, June 1986.

³²Ibid., p. 15.

³³Ibid., p. 186.

³⁴Ibid., p. 192.

Chapter 5

THE COMPARATIVE ECONOMICS OF COAL LIQUID FUELS

5.1 Introduction

As with all large investment projects, there are numerous assumptions one must make in order to calculate the potential economic viability of coal-derived liquid fuels, and differing assumptions will entail a different set of product prices and cost competitiveness. These assumptions include the unit cost of coal, labour, and electricity, annual escalation rates for these unit costs and the selling prices for the various product streams. Technical factors, such as the service factor for the mature plant and the rate at which the plant builds up to its design capacity, must also be determined. In addition, the cost of liquid production will vary depending on the process employed, the scale of operations, location, source of coal, extent of refining of secondary products, methods of financing and taxation.

While some technical risks remain to be resolved in constructing and operating a commercial-sized coal liquids plant, current indications are that economic risks far outweigh the technical risks. However, since full-scale coal/oil co-processing and direct coal liquefaction plants have not yet been built, even the most careful estimates carry some uncertainty. Cost overruns and projections of low rates of return in an environment characterized by oil price uncertainty have led to the postponement of a number of other high cost projects, such as oil sands plants, upgraders and frontier development. The fact that this has occurred to technologies which are closer to being commercialized than coal liquids processes explains why government involvement has been required in virtually all coal liquids technology development to date.

In Canada, the cost of producing coal liquids must be competitive with the cost of production and delivery of frontier oil, synthetic crude oil from integrated oil sands plants and in situ recovery with subsequent upgrading of heavy oil and bitumen. Realistically, such an assessment would call for an evaluation of the cost of coal-derived synthetic fuels within the context of a consistent evaluation

of site-specific alternatives. Such an analysis would entail an examination of actual investment alternatives for specific technologies, at specific locations, using specific feedstocks and making comparable products--all assessed within the framework of a consistent set of technological, economic, social and environmental baseline factors.

The ability to assess Canadian energy supply options on an equal footing is a formidable task compounded by uncertainty associated with the many variables underlying a site-specific assessment of supply options. To a degree, this level of detail is beyond the scope of this study. This is due in large part to the many uncertainties associated with the geological, cost, technical, environmental, and social risks associated with the different process technologies and supply options available to Canada. Given these uncertainties, the analysis presented in this chapter should appropriately be considered as an economic scoping assessment of the potential for coal-derived synthetic fuels development in Canada.

The term "scoping" is important; while the most up-to-date data have been employed in the analysis, this information remains preliminary, as much of the costing data for Canada's supply options are based on estimated engineering costs. Typically, as technological development proceeds, problems are encountered and solved at a cost, and the engineer's original concept of the plant is gradually replaced with a more refined understanding of how the plant will actually work. As a consequence, cost evaluations based on less-developed technologies are less accurate, with early estimates tending to understate the true costs by larger margins than those based on more developed and well-defined technologies.

As such, the accuracy of preliminary engineering costs can be truly assessed only after a number of years of operation has allowed optimization of procedures and solutions to bottlenecking problems. Since such activities may take in the order of 5 years, comparisons on an equal footing translate to an evaluation of the cost of expanding existing facilities such as Canada's integrated mined oil sands plants. These are the only truly representative costs of new plants, since they pertain to proven, in-place commercial technology. To a large degree, all other cost comparisons are equally hypothetical, being premised on preliminary engineering assessments of the costs and expected operability of plants built for Canadian conditions.

The supply cost analysis of production and capacity development of upgraders, mined oil sands plants and coal liquids facilities presented below is based on a complete reassessment of the potential costs of all of Canada's major energy supply options. The prospective sequencing and development of these supply options was appraised against a re-evaluation of Canadian demand for crude oil using CERl's CREED model, a regional end-use, multi-fuel energy demand model that accounts for inter-fuel substitution possibilities. This data, together with forecasts of primary energy prices, process technology costs and reserves information, was used with a linear programming model developed by the Alberta Research Council to assess the development of coal/oil co-processing and direct coal liquefaction relative to all other supply options.

The conventional approach in assessing the economic viability of an energy technology is to carry out a standard process economic analysis. This report goes one step further; it imbeds the process economics of coal liquids technology in the framework of a large-scale energy model, which takes into account all competing technologies over a long-term planning horizon. Thus, all energy resources and technologies are compared in an internally consistent manner, under a common set of economic and marketing conditions. The model used in this study allocates on an optimal basis, all the relevant Canadian energy resources--conventional and frontier crude oil, natural gas, bitumen, coal--among the potentially available technologies and also over time. This latter feature is an important consideration in the case of exhaustible resources.

The MITRE evaluation of the technical and economic advances in direct coal liquefaction and the detailed cost and technical assessment of HRI's coal/oil co-processing program published by the Electric Power Research Institute (EPRI) formed the basis of our evaluation of state-of-the-art coal liquids technology. The data presented in these reports was scaled-up for Canadian conditions and was corroborated by information provided by the International Energy Agency, Canadian Energy Developments, Inc., and Ontario-Ohio Synthetic Fuels Corporation. Dr. Norbert Berkowitz, Professor of Fuel Science in the University of Alberta's Department of Mining, Metallurgical and Petroleum Engineering, offered considerable advice on the assumptions made regarding the potential conversion properties of Alberta subbituminous coals, based upon his own knowledge and upon the technical information presented in the MITRE and EPRI reports.

The discussion of the economics of coal-derived synthetic fuels production presented below is one component of a re-evaluation of Canadian supply options undertaken by the Canadian Energy Research Institute over the course of the last year. A forthcoming study entitled "Canadian Oil Market Supply and Demand" will present the complete findings of this assessment of crude oil supply and demand for Canada. The Supply-Demand study was based upon published information from the Institute of Sedimentary and Petroleum Geology, a division of the federal Department of Energy, Mines and Resources. Up-to-date cost and reserves figures for Canada's frontier were validated by individuals experienced in these operations. Oil sands costs, production and energy balances were drawn from a recent Syncrude application to the Alberta Energy Resources Conservation Board.¹ Information on the potential costs of heavy oil/bitumen upgraders and high-conversion bitumen upgrading processes was based on published information. In addition, our assessments were validated with the assistance of many, including two independent Advisory Committees comprised of representatives from industry and government, staff of the Oil Sands Department of the Alberta Research Council, and Professor D. Quon of the University of Alberta.

The chapter opens with a description of the linear programming model used to evaluate the prospective on-stream dates of Canada's various energy supply options. This is followed by a description of the derivation of supply costs for single-stage and two-stage direct coal liquefaction and coal/oil co-processing plants. A description of the potential staging of production from coal liquids, integrated oil sands, and heavy oil/bitumen upgraders is provided together with the results of a series of sensitivity cases. The chapter concludes with recommendations arising from the analytical assessment of the comparative economics of coal-derived synthetic fuels production.

5.2 Energy Modelling at the Alberta Research Council

Since 1975, the Technical and Economic Evaluations group of the Alberta Research Council has been involved in the development and refinement of a suite of large-scale linear programming models. The models were developed to provide decision-makers with an analytical tool which would enable them:

- (1) to assess emerging technologies of interest to Alberta; and
- (2) to focus on pertinent energy issues by providing a long-term perspective on provincial energy resource development schemes.

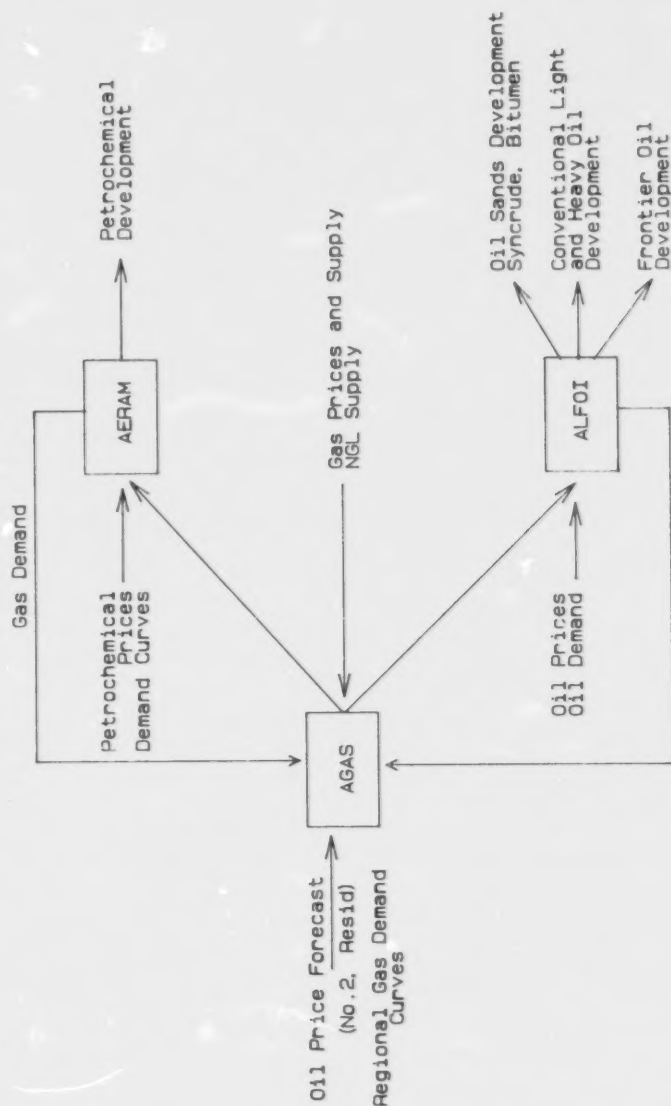
The models have been used to:

- identify key issues for long-term energy planning;
- evaluate the potential benefits of oil sands research;
- evaluate natural gas trade under deregulation; and
- assess the petrochemical market under free trade.

The present configuration consists of three large models represented in Figure 5.1. Each model describes in detail one specific energy sector.

- ALFOI is an oil supply model for Canada projecting, on a yearly basis, the production of liquid fuels over the next 20 years. Given a price projection and a demand trajectory, the model seeks a development and production schedule which maximizes the present value to the oil industry of Canada's liquid fuel resources. In the model, conventional light and heavy crudes from Western Canada, Hibernia and the Beaufort, and coal liquefaction, in situ and mined oil sands projects, are explicitly modelled.
- AGAS is a partial equilibrium natural gas trade model for North America. Both Canadian and U.S. gas supplies and demand are regionalized and modelled explicitly. A pipeline network links supplies to demands and supply/demand is integrated for each region. The model's objective function is to maximize the sum of consumer surplus and producer surplus in both the U.S. and Canada by simulating a free market environment. Given a projection of oil prices, AGAS then generates natural gas demand and city gate prices for each region, a gas exploration and development profile for both the U.S. and Canada, and a Canadian natural gas export profile.
- AERAM is a detailed petrochemical model for Canada covering both the Alberta and Eastern Canada petrochemical sectors. Potential markets include Western Canada, Eastern Canada, U.S. Pacific Northwest, U.S. Midwest and the Pacific Rim countries. Transportation costs and tariffs are considered explicitly. The model focusses on both technical and economic considerations and addresses such issues as feedstock availability and cost, capital availability and cost, technological changes, product prices and export markets. As in ALFOI, given a set of energy and petrochemical price projections, AERAM generates a petrochemical development profile in Canada and identifies the key petrochemicals and markets.

Figure 5.1
Schematic of Alberta Research
Council Models



SOURCE: Alberta Research Council.

These models are optimizing, multi-period, clairvoyant energy supply-demand models which, because of their large size, use a linear programming optimization technique. A linear programming model simulates a market economy, which maximizes the sum of producer and consumer surplus. While it can only approximate reality, the solution represents an upper bound on what the energy sector can achieve, if the proper policy and economic choices are made. All investment and production decisions are made assuming full knowledge of future energy prices, using a 10 percent real rate of return; alternatively, the model can be adjusted to represent industry response which is more risk-averse. Under this treatment, current oil prices must be greater than supply costs before industry will consider investing in capital-intensive energy projects. A risk-adjusted rate of return to capital of 12 percent instead of 10 percent is also used to emulate the higher risk-adjusted returns typical of industry decision-making.

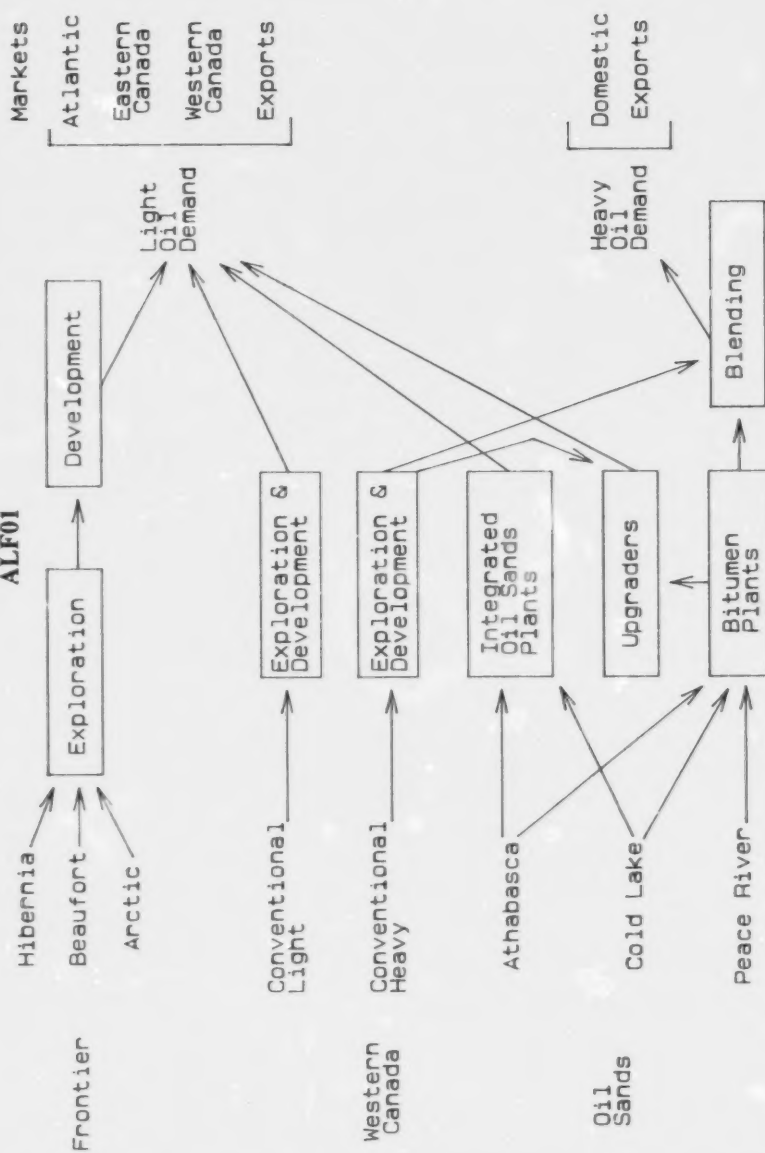
ALFOI, the model used in this study, is a supply model, for which the demands of the various energy products over time are specified exogenously. Supply functions for both light and heavy crude oil in Western Canada and light crude oil from the Canadian frontier are estimated. Costs of producing non-conventional crude oil, such as bitumen and synthetic crude from in situ and mined oil sands plants, are also estimated and entered exogenously. The Canadian demands for liquid fuels (light and heavy crudes, synthetic crude, bitumen blends) are specified for each time period (see Figure 5.2).

The model seeks a development and production profile for the Alberta oil industry that maximizes the present value of the producer surplus generated over the model's time horizon. All past capital expenditures are regarded as sunk, so that the only costs incurred in producing oil from existing conventional oil fields are the marginal or lifting costs of production. Similarly, the only costs incurred by existing mined oil sands and in situ facilities are the marginal operating costs. As the model attempts to simulate the behaviour of producers, all royalties and revenue taxes are regarded as costs.

Some of the model's characteristics are:

- all past capital expenditures are treated as "sunk" costs;
- energy facilities need not operate at capacity;

Figure 5.2
ALF01



SOURCE: Alberta Research Council.

- preproduction activities and costs are modelled explicitly; thus time lags are accounted for in the model;
- production profiles are estimated for each energy development, and capital charges are assigned to each unit of production using the concept of discounted volumes;
- each category of energy development is assigned its own risk-adjusted cost of capital; and
- royalties and revenue taxes are treated as operating costs.

5.3 Direct Coal Liquefaction Economics

The process information and economics presented in the MITRE report for Wyodak subbituminous coal comprised the basis of CERI's assessment of direct coal liquefaction. The CTSI process was chosen as indicative of a state-of-the-art process because HRI's Catalytic Two-Stage Liquefaction showed the best yields and lowest required product selling prices among the process configurations evaluated by MITRE. The HRI single-stage H-Coal process was also included to provide a comparison of two-stage direct liquefaction relative to earlier single-stage process configurations.

The information presented in Table 5.1 shows the derivation of capital and operating costs for the H-Coal single-stage process using an illustrative 10 percent discount rate. Cost information from the MITRE report was adjusted to 1987 dollars using the Chemical Engineering Plant Index and the common practice of adding an additional 20 percent was applied to reflect an Alberta location. The forecast assumed a Canadian to U.S. dollar exchange rate of \$0.75 over the entire period, for an overall U.S./Canadian conversion factor of 1.712. The conversion properties of Alberta subbituminous coals were assumed sufficiently similar to the Wyodak subbituminous coals upon which MITRE based its analysis, and consequently no capital or operating cost add-factor was applied.

As indicated at the bottom of Table 5.1, the capital and operating cost charges for single-stage direct coal liquefaction total \$43.62 per barrel, net of coal feedstock costs. Feedstock costs are accounted for on a yearly basis in the linear programming model corresponding to the real escalation in coal and gas prices. The forecast of primary energy prices used in the base or reference case is

TABLE 5.1
HRI H-COAL SINGLE-STAGE
LIQUEFACTION PROCESS

(1) <u>Basis for Evaluation:</u>		- May 1981 U.S. dollars
		- U.S. location
		- Wyodak subbituminous coal
(2) <u>Conversion to Alberta Site</u>	<u>Multiple</u>	
Update to \$1987	1.07	
Update to Alberta Location	1.20	
Cdn.\$/U.S.\$ Exchange Rate	0.75	
Overall Conversion Factor	1.712	
(3) <u>Construction Costs</u>	<u>Millions 1987 \$Cdn.</u>	
Total Construction Cost ^a	5199	
Paid-up Royalties	33	
Initial Catalyst and Chemicals	53	
Start-up and Initial Costs	162	
Working Capital	204	
Construction Period	5 years	
Operation Period	25 years	
Load Factor After Shakedown	90 percent	
(4) <u>H-Coal Operating Cost @ 90% Operating Factor</u>	<u>Millions 1987 \$Cdn.</u>	
Electric Power	90.3	
Catalysts	78.9	
Purchased Water	1.5	
Operating Labour	18.7	
Administrative Overhead	11.2	
Maintenance	182.0	
Local Taxes and Insurance	103.9	
Solids Disposal	9.0	
Total Operating Costs	495.5 ^b	

(Continued on Next Page)

TABLE 5.1 (cont'd)

(5) Inputs

	<u>Millions of Short Tons/Year</u>
Coal: Liquefaction	10.95
Steam	1.22
Gasifier	<u>.69</u>
Total	12.86

Outputs

	<u>Millions Barrels/Year</u>
Liquid - C ⁴ -850°F Raw	30.92
C ⁴ -850°F Hydrotreated	31.96
Coal	Tons/Barrel
Yield	Barrels/ton liquid
Hydrogen	Weight % MF coal
Liquid Quality	29.5 °API, 11.62% H; 0.70% O; 0.32% N, 0.06% S

^aIncluding engineering design and project contingency of 25 percent.

^bBy-product credits were not included in order to be conservative in the cost estimates.

(Continued on Next Page)

TABLE 5.1 (cont'd)

(6) HRI H-COAL SINGLE-STAGE LIQUEFACTION PROCESS
DISCOUNTED CASH FLOW ANALYSIS

Year	Construction Profile (% investment; % production)	Production (MMB/yr.)	Construction Cost (MM\$)	Capital Expend. (MM\$)	Operating Cost (MM\$)
-5	0.026		135		
-4	0.132		686		
-3	0.307		1596		
-2	0.348		1809		
-1	0.182		946		
Present value discounted at 10%			6577		
Initial outlays			452		
1	0.57	18.06		7029	495.5
2	0.83	26.53			495.5
3	0.89	28.32			495.5
4	0.90	28.76			495.5
5	0.90	28.76			495.5
6	0.90	28.76			495.5
7	0.90	28.76			495.5
8	0.90	28.76			495.5
9	0.90	28.76			495.5
10	0.90	28.76			495.5
11	0.90	28.76			495.5
12	0.90	28.76			495.5
13	0.90	28.76			495.5
14	0.90	28.76			495.5
15	0.90	28.76			495.5
16	0.90	28.76			495.5
17	0.90	28.76			495.5
18	0.90	28.76			495.5
19	0.90	28.76			495.5
20	0.90	28.76			495.5
21	0.90	28.76			495.5
22	0.90	28.76			495.5
23	0.90	28.76			495.5
24	0.90	28.76			495.5
25	0.90	28.76		-204	495.5
Discounted @ 10%		249.2		6371.5	4497.4
Capital charges			\$/bbl	\$25.57	
Operating charges			\$/bbl	<u>\$18.05</u>	
Total supply cost (net of feedstock)			\$/bbl	\$43.62	

SOURCES: The MITRE Corporation. A Techno-Economic Assessment of Recent Advances in Direct Coal Liquefaction, 1986, Appendix A; Alberta Research Council and Canadian Energy Research Institute.

presented in Tables 5.2a and 5.2b. As an example, subbituminous coal at the minemouth of \$13/ton is assumed to have a delivered price of \$21/ton after beneficiation and transportation charges are accounted for. It is this cost of coal on a moisture-ash-free (MAF) basis which is included in the annual derivation of supply costs for direct coal liquefaction. No real escalation in the costs of low rank subbituminous coal is assumed over the forecast horizon.

Of particular note in the analysis of direct liquefaction processes is that gasification of residues and coal gasification were assumed as sources of hydrogen for the upgrading of subbituminous coal to synthetic crude oil. It is recognized that steam reforming of fuel gas and natural gas is a commercially-proven method of producing hydrogen and is currently a less costly process than hydrogen production by gasification of the residue. However, since we relied on the process technology and capital cost information supplied in the MITRE report, our analysis was constrained to the methods MITRE chose for hydrogen production. To account for the potential improvements in process technology, capital costs were reduced by 10 percent.

The cost estimates shown in Table 5.1 are intentionally conservative, in that no allowance has been made for by-product sales of such products as sulphur and ammonia. While this is not an onerous constraint, excluding by-product credits causes total operating costs in Canadian dollars to be some 5 percent higher than MITRE's evaluation. A further degree of conservatism in the cost estimates is reflected in the use of a constant Canadian/U.S. dollar exchange rate of \$0.75 for the entire forecast period. If a figure of \$0.78 were assumed, the overall conversion factor used to convert U.S. capital and operating costs would fall by over 6 percent; an exchange rate of \$0.81 would yield a reduction in Canadian capital and operating costs of over 12 percent. Taken together, these assumptions suggest that capital and operating charges of \$43.62 per barrel are a relatively conservative estimate of the cost of single-stage direct coal liquefaction for an Alberta location.

Table 5.3 shows the calculated capital and operating costs of HRI's Catalytic Two-Stage Liquefaction process. Excluding feedstock costs and using an illustrative 10 percent return to capital, total production costs come to \$35.29 per barrel. Assuming a more risk-averse 12 percent discount rate, total supply costs including feedstock costs are constant for single and two-stage processes at \$54.32 and \$44.38 (\$1986) per barrel, respectively. Supply costs are constant

TABLE 5.2a
FORECAST OF PRIMARY ENERGY PRICES
REFERENCE CASE
(\$1986)

Year	Light Oil Chicago (\$U.S./b)	Alberta Well-Head (\$Cdn./b)	Toronto City-Gate (\$Cdn./b)	Maritimes (\$Cdn./b)	Heavy Oil (\$Cdn./b)
1987	19.00	23.81	25.31	25.33	20.46
1989	19.25	24.85	26.35	26.37	21.31
1991	21.33	27.30	28.80	28.82	23.03
1993	23.09	29.27	30.77	30.79	24.29
1995	25.00	31.37	32.87	32.89	25.70
1997	25.78	31.96	33.46	33.48	25.63
1999	26.59	32.57	34.07	34.09	25.59
2001	27.40	33.61	35.11	35.13	25.87
2003	28.18	34.61	36.11	36.13	26.10
2005	29.00	35.66	37.16	37.18	26.39
2007	29.78	36.66	38.16	38.18	27.38
2009	30.60	37.71	39.21	39.23	28.42
2011	31.40	38.74	40.24	40.26	29.44
2013	32.20	39.76	41.26	41.28	30.45
2015	33.00	40.79	42.29	42.31	31.47

SOURCE: Alberta Research Council and Canadian Energy Research Institute.

TABLE 5.2b

FORECAST OF ENERGY PRICES - REFERENCE CASE
(\$1986)

Year	Heavy Oil Blend (\$Cdn./b)	Synthetic Crude (\$Cdn./b)	Bitumen Blend (\$Cdn./b)	Bitumen (\$Cdn./b)	Natural Gas (\$Cdn./Mcf)	Subbituminous Coal (\$Cdn./ton)
1987	21.15	24.81	18.10	14.65	2.16	21.00
1989	22.04	25.85	18.99	15.44	2.44	21.00
1991	23.89	28.30	20.84	16.93	2.72	21.00
1993	25.27	30.27	22.22	17.97	3.02	21.00
1995	26.81	32.37	23.76	19.17	3.32	21.00
1997	26.84	32.96	23.79	18.90	3.63	21.00
1999	26.91	33.57	23.86	18.69	3.94	21.00
2001	27.30	34.61	24.25	18.74	4.25	21.00
2003	27.66	35.61	24.61	18.75	4.57	21.00
2005	28.07	36.66	25.02	18.81	4.88	21.00
2007	29.07	37.66	26.02	19.79	5.19	21.00
2009	30.12	38.71	27.07	20.81	5.40	21.00
2011	31.15	39.74	28.10	21.81	5.71	21.00
2013	32.18	40.76	29.13	22.81	6.01	21.00
2015	33.20	41.79	30.15	23.81	6.32	21.00

SOURCE: Alberta Research Council and Canadian Energy Research Institute.

TABLE 5.3
HRI CATALYTIC TWO-STAGE LIQUEFACTION

(1) <u>Basis for Evaluation:</u>		- May 1981 U.S. dollars - U.S. location - Wyodak subbituminous coal - Cost estimate based on 1981 commercial design of Lummus ITSL plant
(2) <u>Conversion to Alberta Site</u>		<u>Multiple</u>
Update to \$1987		1.07
Update to Alberta Location		1.20
Cdn.\$/U.S.\$ Exchange Rate		0.75
Overall Conversion Factor		1.712
(3) <u>Construction Costs</u>		<u>Millions 1987 \$Cdn.</u>
Total Construction Cost ^a		5636
Paid-up Royalties		33
Initial Catalyst and Chemical		53
Start-up and Initial Costs		176
Working Capital		221
Construction Period		5 years
Operation Period		25 years
Load Factor After Shakedown		90 percent
(4) <u>H-Coal Operating Cost @ 90% Operating Factor</u>		<u>Millions 1987 \$Cdn.</u>
Electric Power		90.3
Catalysts		78.9
Purchased Water		1.5
Operating Labour		18.7
Administrative Overhead		11.2
Maintenance		197.2
Local Taxes and Insurance		112.6
Solids Disposal		10.7
Total Operating Costs		521.1 ^b

(Continued on Next Page)

TABLE 5.3 (cont'd)

(5) Inputs

	<u>Millions of Short Tons/Year</u>
Coal: Liquefaction	10.95
Steam	1.61
Gasifier	<u>3.23</u>
Total	15.79

Outputs

	<u>Millions Barrels Per Year</u>
Liquid - C ⁴ -850°F Raw	40.46
C ⁴ -850°F Hydrotreated	42.27
Coal Input	Tons/Barrel 0.374
Yield	Barrels/ton liquid 3.86
Hydrogen Consumption	Weight % MF coal 6.62
Liquid Quality	28.5°API; 11.8% H; 0.34% O; 0.12% N; 0.04% S.

^aIncluding engineering design and project contingency of 25 percent.

^bBy-product credits were not included, in order to be conservative in the cost estimates.

(Continued on Next Page)

TABLE 5.3 (cont'd)

(6) HRI CATALYTIC TWO-STAGE LIQUEFACTION PROCESS
DISCOUNTED CASH FLOW ANALYSIS

Year	Construction Profile (% investment; % production)	Production (MMB/yr.)	Construction Cost (MM\$)	Capital Expend. (MM\$)	Operating Cost (MM\$)
-5	0.026		147		
-4	0.132		744		
-3	0.307		1730		
-2	0.348		1961		
-1	0.182		1026		
Present value discounted at 10%			7130		
Initial outlays			482		
1	0.57	23.88		7612	521.1
2	0.83	35.08			521.1
3	0.89	37.45			521.1
4	0.90	38.04			521.1
5	0.90	38.04			521.1
6	0.90	38.04			521.1
7	0.90	38.04			521.1
8	0.90	38.04			521.1
9	0.90	38.04			521.1
10	0.90	38.04			521.1
11	0.90	38.04			521.1
12	0.90	38.04			521.1
13	0.90	38.04			521.1
14	0.90	38.04			521.1
15	0.90	38.04			521.1
16	0.90	38.04			521.1
17	0.90	38.04			521.1
18	0.90	38.04			521.1
19	0.90	38.04			521.1
20	0.90	38.04			521.1
21	0.90	38.04			521.1
22	0.90	38.04			521.1
23	0.90	38.04			521.1
24	0.90	38.04			521.1
25	0.90	38.04		-221	521.1
Discounted @ 10%		329.6		6900.0	4730.4
Capital charges			\$/bbl	\$20.94	
Operating charges			\$/bbl	<u>\$14.35</u>	
Total supply cost (net of feedstock)			\$/bbl	\$35.29	

SOURCES: The MITRE Corporation. A Techno-Economic Assessment of Recent Advances in Direct Coal Liquefaction, 1986, Appendix A; Alberta Research Council and Canadian Energy Research Institute.

over the entire forecast period as no real escalation in subbituminous coal prices is assumed. As noted in the descriptive information presented in earlier chapters, two-stage direct liquefaction has indeed resulted in a significant improvement in the relative economics of direct coal liquefaction. Including coal feedstock costs, the two-stage process represents only 82 percent of the total supply cost of the single-stage direct liquefaction process. As noted above, these figures reflect a conservative bias and site-specific assessments could show some further reduction in the total supply costs of direct liquefaction processes.

5.4 Coal/Oil Co-Processing Economics

The single-stage HRI coal/oil co-processing costs taken from the recent Electric Power Research Institute (EPRI) Phase I study and adjusted for an Alberta location are shown in Table 5.4. As the economic analysis presented in the EPRI report was based on Ohio bituminous coal, an additional 5 percent surcharge was applied to the U.S. capital cost data to account for the increase in capital costs for additional hydrogen required to convert subbituminous coal to synthetic crude oil. On the operating cost side, an additional 1.6 Bcf/yr. of natural gas was also included for the higher hydrogen consumption required to produce 14,200 b/d of synthetic crude oil from Alberta subbituminous coal. Steam reforming of natural gas provided the hydrogen for co-processing and product hydrotreating and a coal-to-oil ratio of 1:1 was used as presented in EPRI's Case 2 continuous bench unit evaluation of single-stage coal/oil co-processing.

The economic analysis presented below is based on single-stage co-processing of coal and oil. Detailed cost and process information for two-stage catalytic coal/oil co-processing, the basis of the prototype commercial plant in the United States, were not available at the time of analysis. Pending additional demonstration of the conversion properties of Alberta subbituminous coals, the costs for single-stage coal/oil co-processing were believed to represent a reasonable estimate of the costs of coal/oil co-processing in an Alberta context. In recognition, however, of the potential benefits of the two-stage catalytic process configuration and of the likelihood of further improvements stemming from demonstration of the U.S. prototype commercial coal/oil co-processing plant, a 10 percent reduction in capital and operating costs was assumed for post-demonstration plants built in the later 1990s. As noted earlier, this is only one-half of the

TABLE 5.4
HRI COAL/OIL CO-PROCESSING

- (1) Basis for Evaluation: - HRI Single-Stage Coal/Oil Co-processing
 - EPRI Coal/Oil Co-processing, March 1987
 - 1986 \$U.S. @ U.S. Gulf Coast location.

- (2) Conversion to Alberta Site
 Update to Alberta Location 1.2
 \$Cdn./\$U.S. Exchange Rate 0.75
 Overall Conversion Factor 1.60

(3) Construction Costs

Undiscounted Construction Costs		U.S. \$MM	261		
Discount Rate		Percent	10		
Year	Construction Profile	Construction Cost MM\$	Preproduction Cost	Working Capital	Total
-3	0.25	65.3			
-2	0.50	130.5			
-1	0.25	65.3			
0		316.5	10.3	18.4	345.3
Alberta Site \$Cdn.		506.4	16.5	29.4	552.4
Capital Increased 5% for Additional Hydrogen Requirements		531.8	17.4	30.9	580.0
Construction Period		3 years			
Operation Period		25 years			
Load Factor After Shakedown		90 percent			

(4) Operating Costs @ 100% Operating Factor

	Million 1987 \$Cdn.
Electricity	5.50
Cooling Water	0.17
Process Water	0.07
Boiler Feed Water	0.06
Low Pressure Steam	0.12
High Pressure Steam (Credit)	-0.37
Catalyst	3.0
Maintenance	25.54
Total @ 100% operating factor	34.09
@ 90% operating factor	33.24

(Continued on Next Page)

TABLE 5.4 (cont'd)

(5) Process:

- Single-Stage, bottom disposal-Coking
- Oil/coal ratio of 1:1,
- coal conversion 93% MAF; 975 + conversion 75% MAF

Inputs:

Coal	MMT/yr.	0.547
Cold Lake Residuum	MMbbl/yr.	3.07
Natural Gas	BCF/yr.	4.40

Outputs:

Syncrude C ⁴ -975°F	MMbbl/yr.	5.18
API 30.8; H 12%; S 0.22 %; N 0.25%.		

(Continued on Next Page)

TABLE 5.4 (cont'd)

(6) HRI COAL/OIL CO-PROCESSING
DISCOUNTED CASH FLOW ANALYSIS

Year	Fraction of Full Production	Production (MMB/yr.)	Capital Expenditure (MM\$)	Operating Cost (MM\$)
1	0.565	2.93	580.0	33.2
2	0.830	4.30		33.2
3	0.886	4.59		33.2
4	0.900	4.66		33.2
5	0.900	4.66		33.2
6	0.900	4.66		33.2
7	0.900	4.66		33.2
8	0.900	4.66		33.2
9	0.900	4.66		33.2
10	0.900	4.66		33.2
11	0.900	4.66		33.2
12	0.900	4.66		33.2
13	0.900	4.66		33.2
14	0.900	4.66		33.2
15	0.900	4.66		33.2
16	0.900	4.66		33.2
17	0.900	4.66		33.2
18	0.900	4.66		33.2
19	0.900	4.66		33.2
20	0.900	4.66		33.2
21	0.900	4.66		33.2
22	0.900	4.66		33.2
23	0.900	4.66		33.2
24	0.900	4.66		33.2
25	0.900	4.66	-30.9	33.2
Discounted @ 10%		40.4	524.5	301.7
Capital charges		\$/bbl	\$12.99	
Operating charges		\$/bbl	<u>\$ 7.47</u>	
Total Supply Cost (net of feedstock)			\$20.46	

SOURCES: Electric Power Research Institute, Coal/Oil Co-Processing, Phase I, 1987; Alberta Research Council and Canadian Energy Research Institute.

improvement in unit costs that has been realized in moving from the single- to two-stage process configuration in direct coal liquefaction.

The cost data in Table 5.4 for the single-stage coal/oil co-processing configuration were deemed fair and representative costs for a prototype commercial (demonstration) co-processing plant built in Alberta and appear a reasonable basis for comparison with the costs of Canada's other supply options. While it seems very likely that coal/oil co-processing costs will be lower than this, demonstration of the technology, optimized for Canadian conditions, is required to actually prove the economics, operability and conversion of Alberta subbituminous coals. A lag period of 4 years following initial production from the demonstration plant was incorporated in the model to allow for the lead-time required before sufficient learning experience would translate to a 10 percent cost saving for new commercial co-processing facilities.

As shown in Table 5.4, the combined capital and operating costs, net of coal, natural gas and Cold Lake residuum, is \$20.46 per barrel. The forecast of total supply costs including fuel and feedstock at a return to capital of 12 percent is presented in Table 5.5 for the various coal liquefaction processes.

5.5 Economics of Upgraders

The derivation of representative supply costs for heavy oil/bitumen upgraders was based on the Husky Oil Environmental Impact Statement of July 1985.² Capital costs were first adjusted to a 1987 dollar basis and subsequently reduced by 10 percent to account for cost rationalization since the original proposal. This process uses a low (65 percent) conversion ebullated-bed hydrocracking process developed by HRI to upgrade both heavy oil and crude bitumen.³

As shown in Table 5.6, the amortized unit capital charges for low conversion upgraders at a 12 percent return to capital are \$8.58 per barrel. Operating costs, excluding heavy crude oil, Cold Lake bitumen and natural gas feedstocks are \$2.88 for a total of \$11.46 per barrel. The total supply costs including fuel and feedstock for the Husky-type low conversion upgrader are depicted in Table 5.7 for the 1987 to 2015 period.

The upgrading costs for high conversion (95 percent) bitumen upgraders are also depicted in Tables 5.6 and 5.7. Unit capital

TABLE 5.5
REFERENCE CASE SUPPLY COSTS FOR COAL/OIL CO-PROCESSING
AND COAL LIQUEFACTION PLANTS
(1986 \$Cdn./bbl)

Year	Coal/Oil Co-Processing		Direct Liquefaction	
	Demonstration Plant	Commercial Plant	Catalytic Two-Stage	H-Coal Single-Stage
1987	39.21	36.95	44.38	54.32
1989	39.45	37.19	44.38	54.32
1991	39.69	37.43	44.38	54.32
1993	39.94	37.68	44.38	54.32
1995	40.20	37.94	44.38	54.32
1997	40.46	38.20	44.38	54.32
1999	40.72	38.46	44.38	54.32
2001	40.99	38.73	44.38	54.32
2003	41.26	39.00	44.38	54.32
2005	41.52	39.26	44.38	54.32
2007	41.79	39.53	44.38	54.32
2009	41.96	39.70	44.38	54.32
2011	42.23	39.97	44.38	54.32
2013	42.48	40.22	44.38	54.32
2015	42.75	40.49	44.38	54.32

SOURCE: Alberta Research Council and Canadian Energy Research Institute.

NOTE: Discount rate 12 percent.

TABLE 5.6
SUPPLY COST COMPARISON
(1986 \$Cdn.)

	MCG (\$/bbl)	DSR (%)	AED (\$/bbl)	OPR (\$/bbl)	TOT (\$/bbl)
<u>Oil Sands Plants and Upgraders</u>					
MS1	5.71	12	22.46	12.10	34.56
MSB	3.37	12	9.46	10.00	19.46
HCl	2.16	12	6.05	5.06	11.11
SP1	3.15	12	9.34	4.89	14.23
HUP	2.60	12	8.58	2.88	11.46
UPG	2.86	12	9.42	4.44	13.86
<u>Coal Liquids</u>					
CL1	4.58	12	15.10	7.47	22.57
CL1	4.12	12	13.59	6.72	20.31
CB1	7.39	12	24.52	14.35	38.87
CB2	9.03	12	29.97	18.05	48.02

SOURCE: Alberta Research Council and Canadian Energy Research Institute.

NOTE: Net of fuel and feedstock.

LEGEND: MCG - Pre-production Cost, \$/bbl In-ground
 DSR - Discount Rate, %
 AED - Amortized Pre-production Costs, \$/bbl
 OPR - Operating Costs, \$/bbl
 TOT - Total Cost

MS1 - Integrated Oil Sands Plants
 MSB - Mined Oil Sands Bitumen
 HCl - Esso Cold Lake Bitumen
 SP1 - Peace River Bitumen
 HUP - Heavy Oil/Bitumen Upgrader (Low Conversion)
 UPG - Bitumen Upgrader (High Conversion)
 CL1 - Coal/Oil Co-processing Demonstration Plant
 CL2 - Commercial Coal/Oil Co-processing Plant
 CB1 - Two-Stage Direct Liquefaction (CTSL)
 CB2 - Single-Stage Direct Liquefaction (H-Coal)

TABLE 5.7
SUPPLY COSTS - REFERENCE CASE
(1986 \$Cdn./bbl)

Year	Integrated Oil Sands Plants	Mined Oil Sands Bitumen	Esso Cold Lake Bitumen	Peace River Bitumen	Low Conversion Upgrader	High Conversion Bitumen Upgrader
1987	35.53	19.46	13.75	17.49	31.15	30.08
1989	35.66	19.46	14.09	17.91	32.19	31.08
1991	35.78	19.46	14.43	18.34	34.03	32.78
1993	35.92	19.46	14.80	18.79	35.42	34.03
1995	36.05	19.46	15.16	19.24	36.97	35.46
1997	36.19	19.46	15.54	19.71	37.05	35.43
1999	36.33	19.46	15.92	20.18	37.18	35.45
2001	36.47	19.46	16.30	20.65	37.59	35.74
2003	36.62	19.46	16.69	21.13	37.97	35.99
2005	36.75	19.46	17.07	21.60	38.40	36.29
2007	36.89	19.46	17.45	22.07	39.62	37.50
2009	36.99	19.46	17.70	22.38	40.81	38.68
2011	37.13	19.46	18.08	22.85	42.05	39.91
2013	37.26	19.46	18.45	23.30	43.29	41.13
2015	37.40	19.46	18.82	23.77	44.53	42.36

SOURCE: Alberta Research Council and Canadian Energy Research Institute.

NOTE: Including fuel and feedstock.

charges and operating costs total \$13.86 per barrel, excluding feedstock costs for bitumen and natural gas. A lag constraint was also incorporated in the model to account for the time required before high-conversion upgraders would be commercially proven. While the supply costs shown in Table 5.7 start in 1987, the model restricted capacity additions to 1993 and beyond.

The capital, operating and total supply costs shown in Tables 5.6 and 5.7 for integrated oil sands plants were based on a 1987 application to expand the Mildred Lake plant, submitted by Syncrude Canada Ltd. to the Alberta Energy Resources Conservation Board. As shown in Table 5.7, total production costs including fuel and feedstock for 1987 come to \$35.53 per barrel for integrated mined oil sands plants.

5.6 Comparative Analysis of Supply Options

5.6.1 Supply Costs

Table 5.8 lists the key scenario parameters for the evaluation of supply options under the reference case prices depicted in Table 5.2. A constraint on mined bitumen development and integrated oil sands facilities of one plant of 70,000 b/d every 3 years was assumed, given the size and economic impacts of such developments. All processes were assigned a product price corresponding to the forecast price for synthetic crude oil displayed in Table 5.2. To reflect both the commercial and technical risk of new energy development in an era of expected low and uncertain energy prices, a constraint was added to the model such that the price of synthetic crude oil must exceed supply costs before new capacity is brought on stream for oil sands plants, coal liquids plants and frontier development. However, upgrader capacity was staged to come on stream when the forecast of synthetic crude oil prices guaranteed a rate of return to the project in excess of 12 percent. The results presented below are therefore weighted somewhat in favour of upgrader development. This bias is in keeping with expressed concerns reflecting the potential saturation of bitumen export markets, falling conventional crude oil supplies and Canada's need for upgrader capacity, and current government philosophy.

The supply costs of the various options, at a 12 percent discount rate, are graphically displayed in Figures 5.3 and 5.4 alongside forecast synthetic crude oil prices. As indicated in these

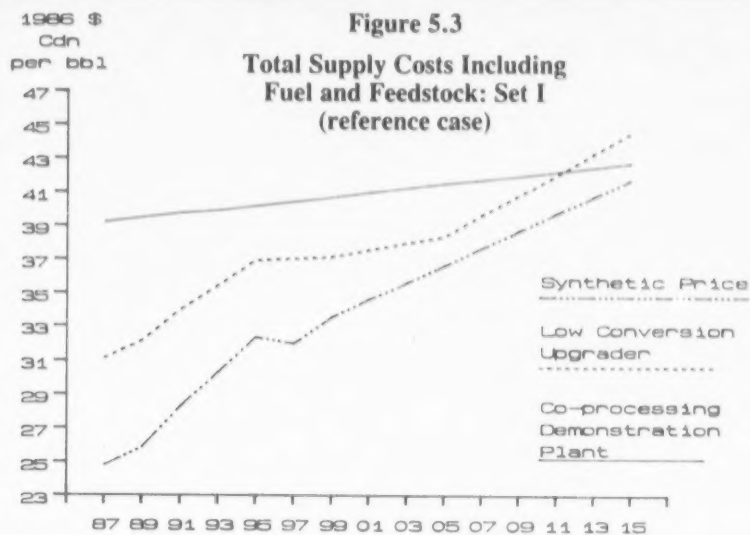
TABLE 5.8
KEY SCENARIO PARAMETERS - REFERENCE CASE

Model Discount Rate % Annual	- 12 percent
Coal Technology Reduction Factor	- 10 percent reduction in capital and operating costs assumed for post-demonstration (commercial) coal/oil co-processing plants.
Price	- Synthetic crude oil product price assumed for oil sands mining plants, upgraders and coal liquids plants.
Financial Results	- Expressed in constant 1986 Canadian dollars.
Coal/Oil Co-Processing Demonstration Plant	- Assumed producing 4.66 MMB/yr. in 1997.
Price Projections	- CERI Reference Case Prices
Limits on Oil Imports	- None
Limits on Light Oil Exports	- Maximum 400 million barrels per year.
Limits on New Oil Sands Development	- One plant of 70,000 barrels/day every three years.
Limits on Heavy/Oil Bitumen Blend Export	- Maximum 170 million barrels per year.
Limits on In-situ Bitumen Development	- None
Capacity Additions	- Coal liquids and oil sands plants assumed to come on-stream when the current oil price is greater than the supply cost; investment in up-grader is based on the prospective price path for synthetic crude oil prices.

SOURCE: Alberta Research Council and Canadian Energy Research Institute.

Figure 5.3

**Total Supply Costs Including
Fuel and Feedstock: Set I
(reference case)**



SOURCE: Canadian Energy Research Institute.

Figure 5.4

**Total Supply Costs Including
Fuel and Feedstock: Set II
(reference case)**



SOURCE: Canadian Energy Research Institute.

graphs, integrated oil sands capacity becomes economic in 2005 when the price of synthetic crude oil matches the cost of production; commercial (post-demonstration) coal/oil co-processing plants become economic in 2012. Figures 5.5 and 5.6 graphically display a supply cost comparison for the mid-1990s--a point in time when all processes are expected to be on a comparable footing in terms of the lead-time required for commercial demonstration. As shown in Figure 5.6, a high conversion bitumen upgrader has a slight cost advantage of \$0.59 per barrel compared to the supply costs of an integrated mined oil sands plant in 1995.

5.6.2 Supply Staging--Reference Case

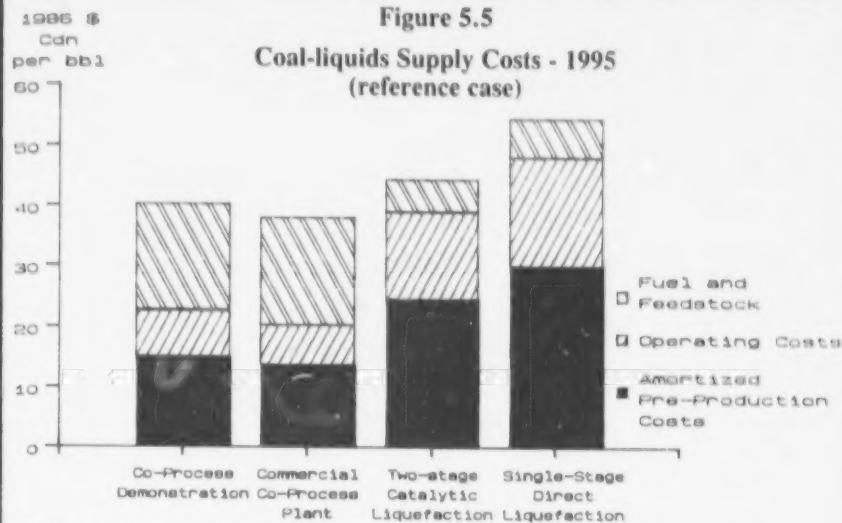
Table 5.9 and Figure 5.7 summarize the reference price case results for the annual production of synthetic crude oil from mined oil sands plants, upgraders and coal liquids process technology. Mined oil sands capacity of 140,000 b/d is started in 2005 and capacity of an additional 140,000 b/d is under construction in 2011. However, production does not come on stream until 2011 at 11.8 MMb/yr. The reference case forecast of crude oil prices and supply costs indicates that investment in low conversion upgraders is uneconomic over the entire forecast horizon. However, capacity in high-conversion bitumen upgraders is economic and is started in 1993 with production coming on stream in 1997 and building to a peak of 32 MMb/yr. By 2015, the relative share contribution of oil sands plants, bitumen upgraders and coal liquids plants to total synthetic crude oil production is 70, 23, and 7 percent, respectively.

Initial development work on a coal/oil co-processing demonstration plant is expected to start in the early 1990s with production of 4.66 MMb/yr. coming on stream in 1997. Experience gained from this demonstration is assumed to result in cost savings which make commercial co-processing capacity of 13 MMb/yr. economic by 2012.

As presented in Figure 5.7, virtually all of the fall-off in production of synthetic crude from oil sands plants at the turn of the century is accounted for by high conversion bitumen upgraders, which reach a peak of 32 MMb/yr. before a new oil sands plant comes into production in 2011. Coal/oil co-processing constitutes a relatively insignificant component of total synthetic crude oil production.

Figure 5.5

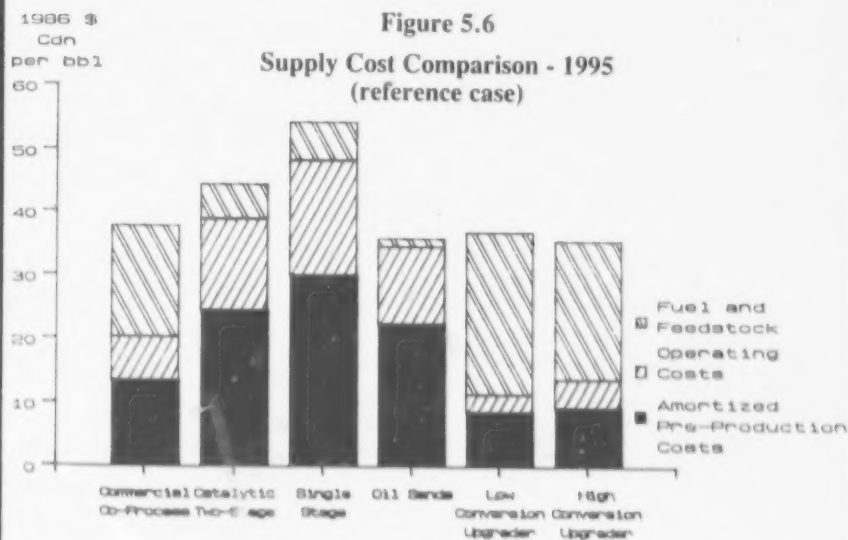
Coal-liquids Supply Costs - 1995 (reference case)



SOURCE: Canadian Energy Research Institute.

Figure 5.6

Supply Cost Comparison - 1995 (reference case)



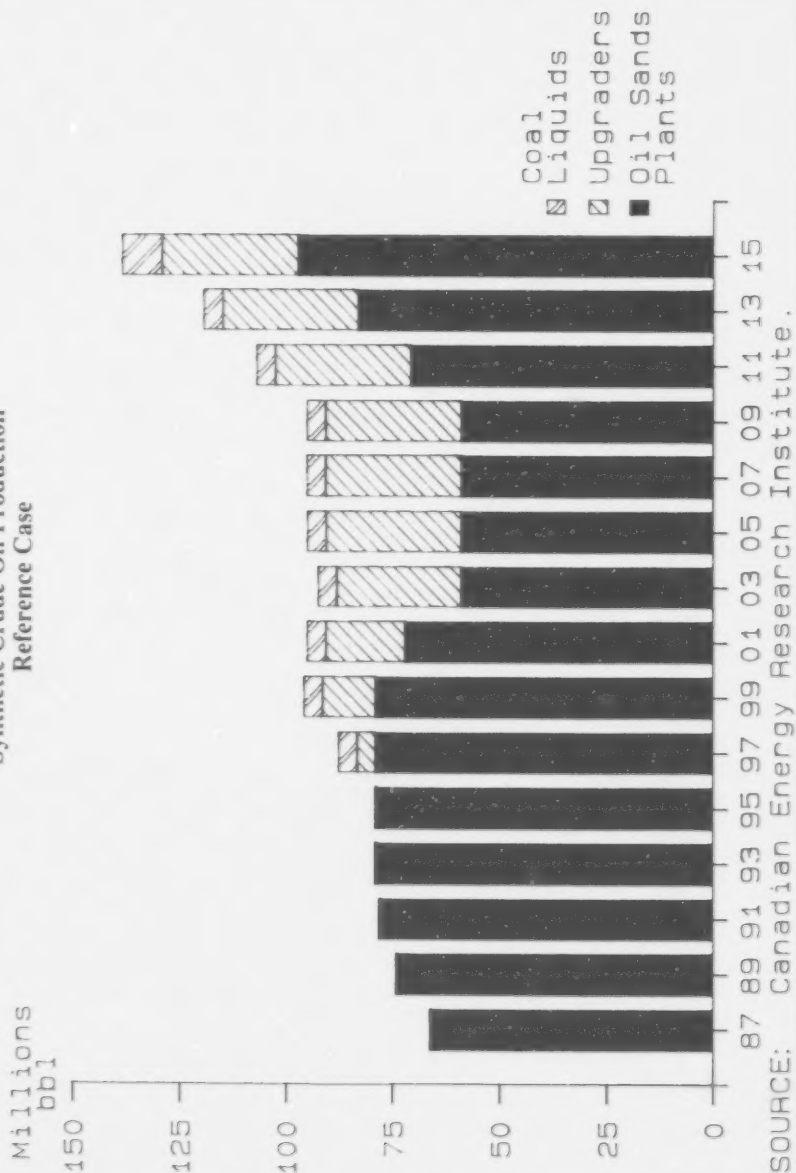
SOURCE: Canadian Energy Research Institute.

TABLE 5.9
REFERENCE CASE, SYNTHETIC CRUDE OIL PRODUCTION
(millions of barrels per year)

Year	Integrated Mined Oil Sands Plants		Coal Liquids Production				Upgrader Operations	
	Existing Plants	New Plants	Total	Co-Processing Demonstration	Co-Processing Commercial	Total	High Conversion	Total
1987	66.0		66.0					
1989	74.0		74.0					
1991	78.0		78.0					
1993	79.0		79.0					
1995	79.0		79.0					
1997	79.0		79.0	4.6		4.6	4.3	4.3
1999	79.0		79.0	4.6		4.6	12.5	12.5
2001	72.0		72.0	4.6		4.6	18.8	18.8
2003	59.0		59.0	4.6		4.6	29.3	29.3
2005	59.0		59.0	4.6		4.6	31.9	31.9
2007	59.0		59.0	4.6		4.6	32.0	32.0
2009	59.0		59.0	4.6		4.6	32.0	32.0
2011	59.0	11.8	70.8	4.6		4.6	32.0	32.0
2013	59.0	24.2	83.2	4.6		4.6	32.0	32.0
2015	59.0	38.3	97.3	4.6	4.9	9.6	32.0	32.0

SOURCE: Canadian Energy Research Institute.

Figure 5.7
Synthetic Crude Oil Production
Reference Case



5.7 Sensitivity Results

A series of sensitivity cases were evaluated using the model in order to assess the implications of potential changes in the forecast price of synthetic crude oil, and in the cost of fuel and feedstocks, on the staging of the various supply options. The first sensitivity case reflects a higher light/heavy oil price differential in the early years of the forecast with all other costs and prices held constant at reference case levels. A set of higher and lower forecasts for primary energy prices was also undertaken to evaluate the impact of forecast price uncertainty on the relative staging of the three major process technologies--oil sands, upgraders and coal liquids plants.

5.7.1 Steeper Light/Heavy Oil Price Differential

The light/heavy crude oil price differential used in this sensitivity case is shown in Figure 5.8 together with the reference case price differential. The reduction in the cost of bitumen relative to the reference case and its flow-through impact on the the total supply costs of both low and high conversion upgraders is shown in Figure 5.9. Figure 5.10 shows the incremental effect of the steeper light/heavy price differential on production of total synthetic crude oil; Table 5.10 displays production by process type. A total level of 140,000 b/d of high conversion upgrader capacity is initiated in the 1993-1997 period resulting in an incremental peak in total synthetic production over the reference case of 27.6 MMb/yr. in 2001. Investment in commercial coal/oil co-processing plants is started in 2010 and total production builds to 26.4 MMb/yr. relative to a reference case level of 9.6 MMb/yr. The area bounded by the two curves in Figure 5.10 shows the incremental impact on total synthetic crude oil output attributable to additional high conversion bitumen upgraders and coal/oil co-processing plants.

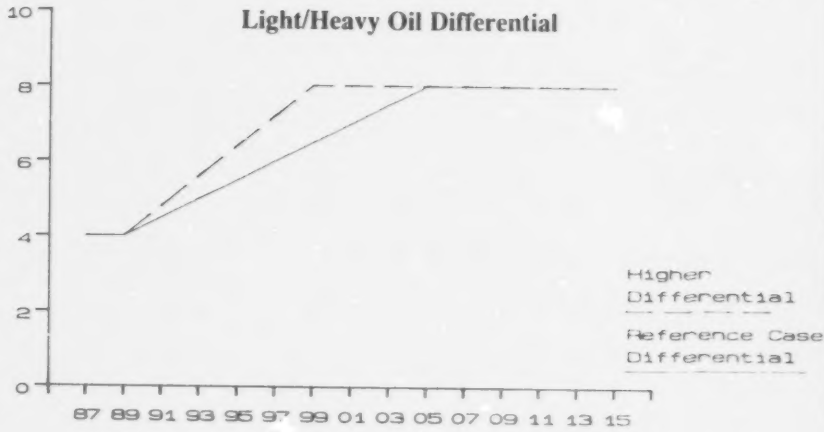
5.7.2 Low Price Case

Figures 5.11 and 5.12 graphically display the difference between the reference price case and low price case for synthetic crude oil and the price of crude bitumen, respectively. Generally, lower energy prices have a moderating effect on the supply costs of oil sands, bitumen upgraders and coal/oil co-processing plants as displayed in Figures 5.13 through 5.15. As shown in these figures, the difference in primary energy prices between the reference and low price case

1986 \$
U.S./bbl

Figure 5.8

Light/Heavy Oil Differential

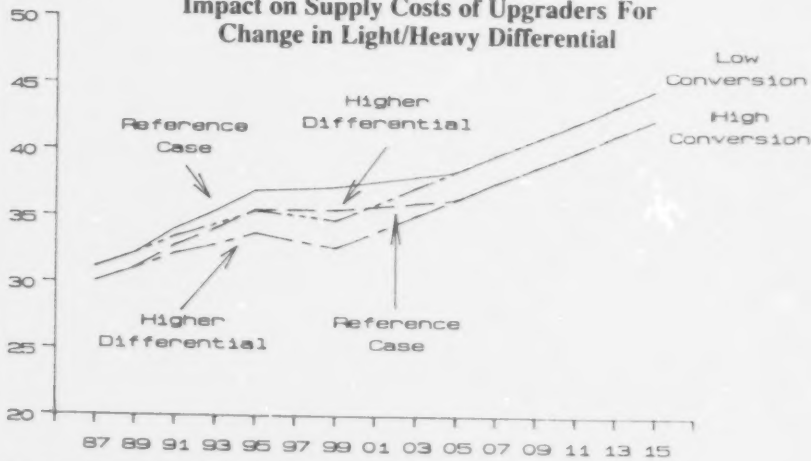


SOURCE: Canadian Energy Research Institute.

1986 \$
Cdn
per bbl

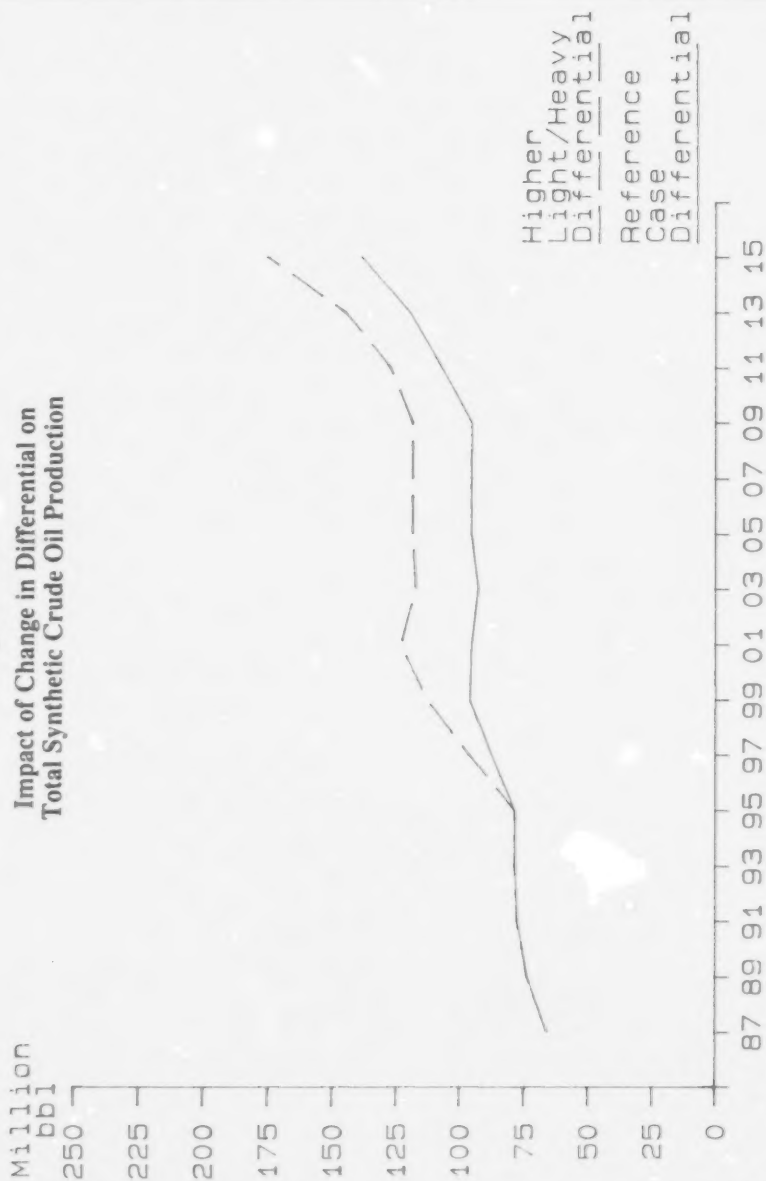
Figure 5.9

Impact on Supply Costs of Upgraders For
Change in Light/Heavy Differential



SOURCE: Canadian Energy Research Institute.

Figure 5.10
Impact of Change in Differential on
Total Synthetic Crude Oil Production



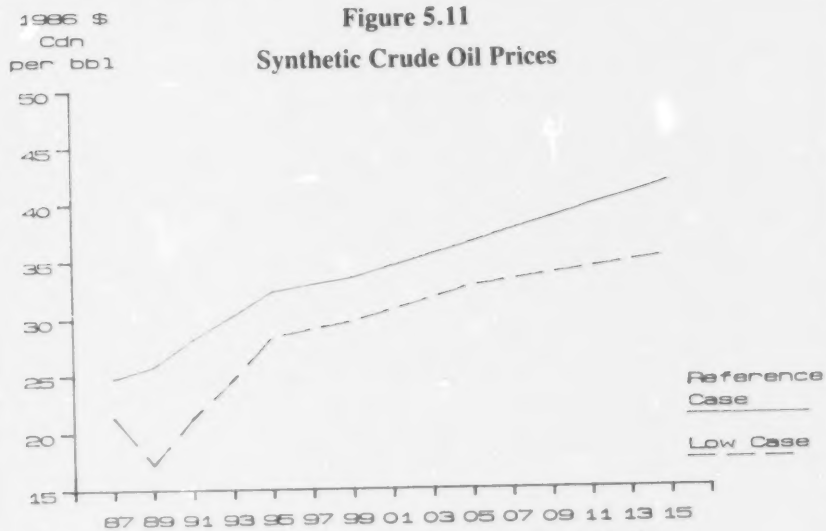
SOURCE: Canadian Energy Research Institute.

TABLE 5.10
 STEEPER LIGHT/HEAVY OIL DIFFERENTIAL CASE,
 SYNTHETIC CRUDE OIL PRODUCTION
 (millions of barrels per year)

Year	Integrated Mined Oil Sands Plants			Coal Liquids Production			Upgrader Operations	
	Existing Plants	New Plants	Total	Co-Processing Demonstration	Co-Processing Commercial	Total	High Conversion	Total
1987	66.0		66.0					
1989	74.0		74.0					
1991	78.0		78.0					
1993	79.0		79.0					
1995	79.0		79.0					
1997	79.0		79.0	4.6		4.6	13.0	13.0
1999	79.0		79.0	4.6		4.6	29.6	29.6
2001	72.0		72.0	4.6		4.6	46.4	46.4
2003	59.0		59.0	4.6		4.6	53.9	53.9
2005	59.0		59.0	4.6		4.6	55.1	55.1
2007	59.0		59.0	4.6		4.6	55.2	55.2
2009	59.0		59.0	4.6		4.6	55.2	55.2
2011	59.0	8.7	67.7	4.6		4.6	55.2	55.2
2013	59.0	21.2	80.2	4.6	5.4	10.0	55.2	55.2
2015	59.0	35.3	94.3	4.6	21.8	26.4	55.2	55.2

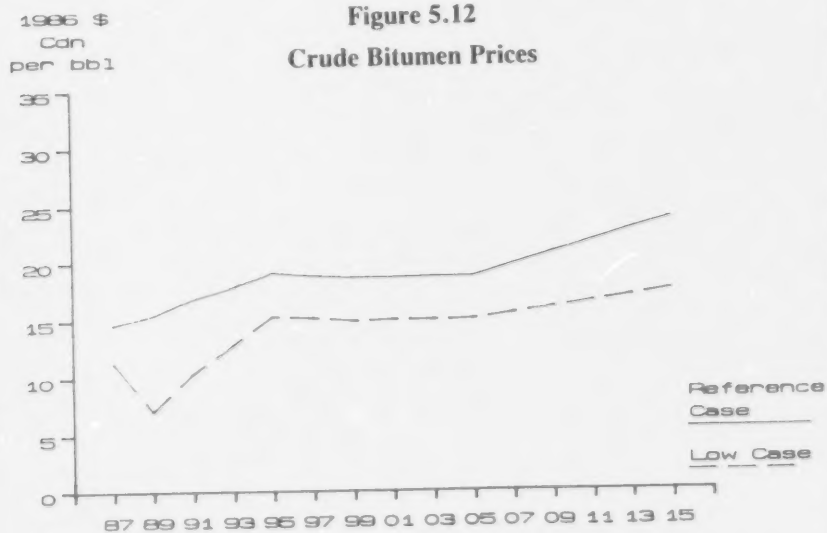
SOURCE: Canadian Energy Research Institute.

Figure 5.11
Synthetic Crude Oil Prices



SOURCE: Canadian Energy Research Institute.

Figure 5.12
Crude Bitumen Prices

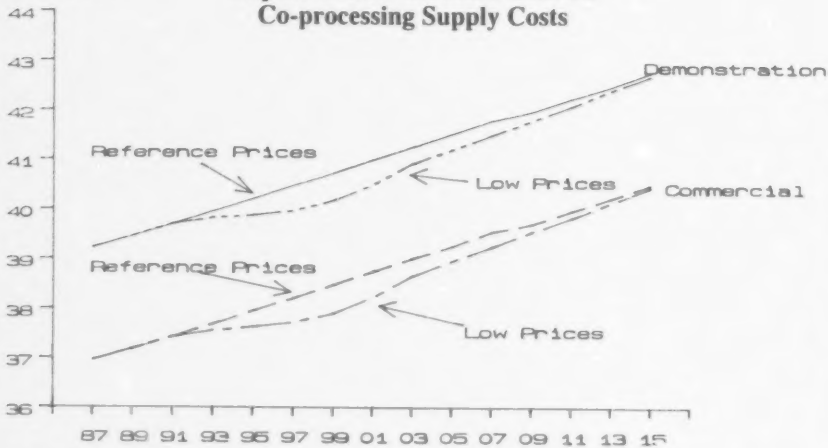


SOURCE: Canadian Energy Research Institute.

1986 \$
Cdn
per bbl

Figure 5.13

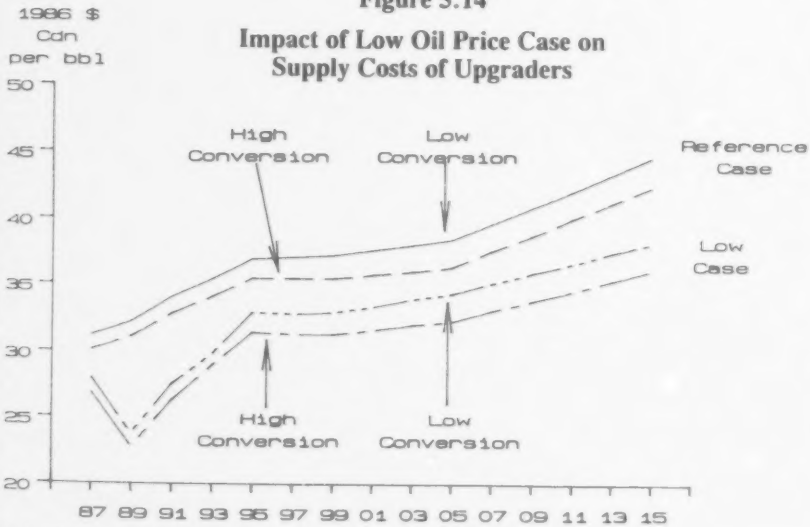
**Impact of Low Oil Price Case on
Co-processing Supply Costs**



SOURCE: Canadian Energy Research Institute.

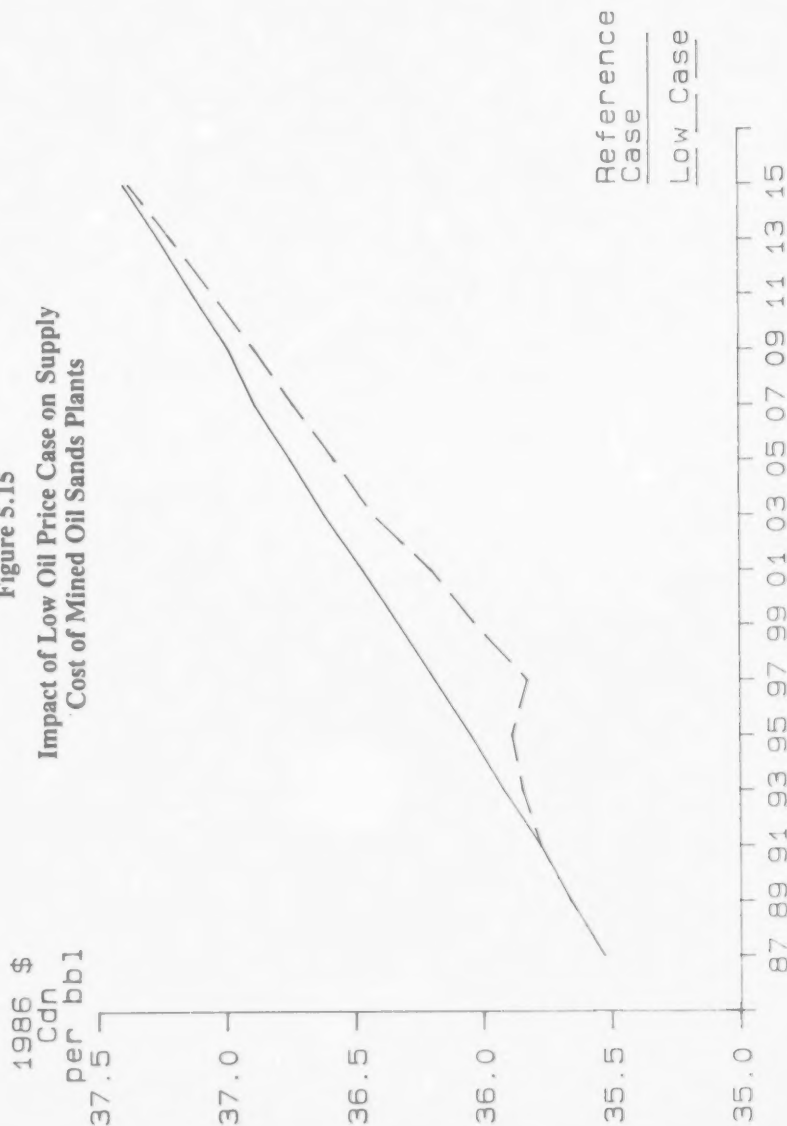
Figure 5.14

**Impact of Low Oil Price Case on
Supply Costs of Upgraders**



SOURCE: Canadian Energy Research Institute.

Figure 5.15
Impact of Low Oil Price Case on Supply
Cost of Mined Oil Sands Plants



SOURCE: Canadian Energy Research Institute.

has a comparatively minor effect on the supply costs of oil sands plants and coal/oil co-processors. Supply costs per barrel peak at a differential of \$0.56 and \$0.30 for co-processors and oil sands plants, respectively. The reduction in supply costs for upgraders as shown in Figure 5.14 averages \$4.80 a barrel for the 1990s, increasing to over \$6.20 per barrel by 2015.

While the fall in supply costs is relatively pronounced, crude oil prices are not sufficient to bring on any new synthetic crude oil productive capacity. Prices are so low in fact that total bitumen production peaks at a level of only 47 percent of reference case bitumen production in 2009. In the reference oil price case, synthetic crude oil production grows from a 1987 level of 66 MMb/yr. to over 138 MMb/yr. in 2015. In the low oil price case, synthetic crude oil builds to a peak of 84 MMb/yr. in 1997 and then falls to 64 MMb/yr. by 2015, leading to a significant increase in oil imports to meet Canadian requirements for light crude oil (see Figure 5.16 and Table 5.11).

5.7.3 High Price Case

Figures 5.17 and 5.18 graphically display the differences between the reference price case and high price case for synthetic crude oil and the price of crude bitumen, respectively. The flow-through impact of generally higher oil and gas prices on the supply costs of coal/oil co-processing plants, upgraders and integrated mined oil sands plants is shown in Figures 5.19 through 5.21. Higher primary energy prices have a relatively minor impact on the supply costs of oil sands plants and coal liquids but the effect on upgraders relative to the reference case is dramatic and builds to a peak differential of over \$11.50 per barrel. The net effect of higher energy prices is depicted in Table 5.12 and Figure 5.22 which show the total production of synthetic crude oil by process type.

As compared to the reference case, synthetic crude oil production is 3.6 times the reference case under higher primary energy prices by 2015. Energy prices are sufficient to bring on both low conversion and high conversion upgraders and a very significant amount of coal-derived synthetic fuels production. Under the high price case, the pace of bitumen and oil sands development is so rapid that the less costly, high-grade bitumen resources are virtually all accounted for. This constraint coupled with high energy prices results in production of two-stage coal liquefaction as early as 2007. By 2015, coal liquids production accounts for 35 percent of total synthetic crude oil,

Figure 5.16
Synthetic Crude Oil Production
Low Price Case



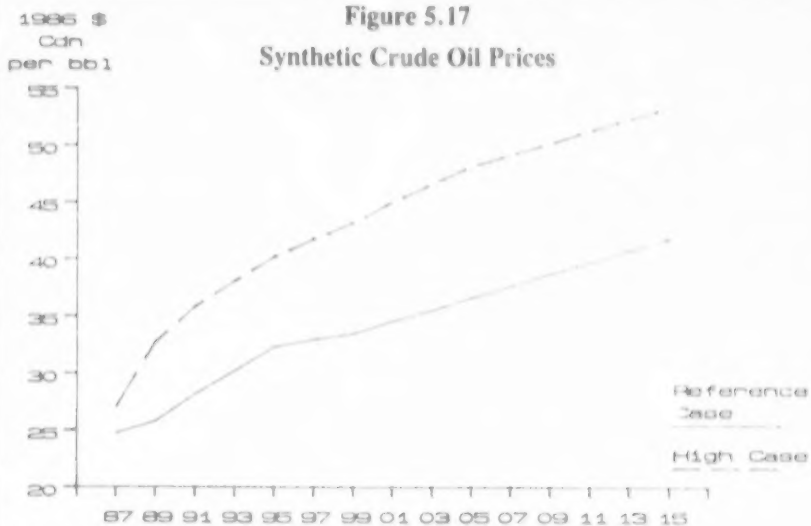
SOURCE: Canadian Energy Research Institute.

TABLE 5.11
LOW PRICE CASE, SYNTHETIC CRUDE OIL PRODUCTION
 (millions of barrels per year)

Year	Integrated Mined Oil Sands Plants		Coal Liquids Production	
	Existing Plants	Total	Co-Processing Demonstration	Total
1987	66.0	66.0		
1989	74.0	74.0		
1991	78.0	78.0		
1993	79.0	79.0		
1995	79.0	79.0		
1997	79.0	79.0	4.6	4.6
1999	79.0	79.0	4.6	4.6
2001	72.0	72.0	4.6	4.6
2003	59.0	59.0	4.6	4.6
2005	59.0	59.0	4.6	4.6
2007	59.0	59.0	4.6	4.6
2009	59.0	59.0	4.6	4.6
2011	59.0	59.0	4.6	4.6
2013	59.0	59.0	4.6	4.6
2015	59.0	59.0	4.6	4.6

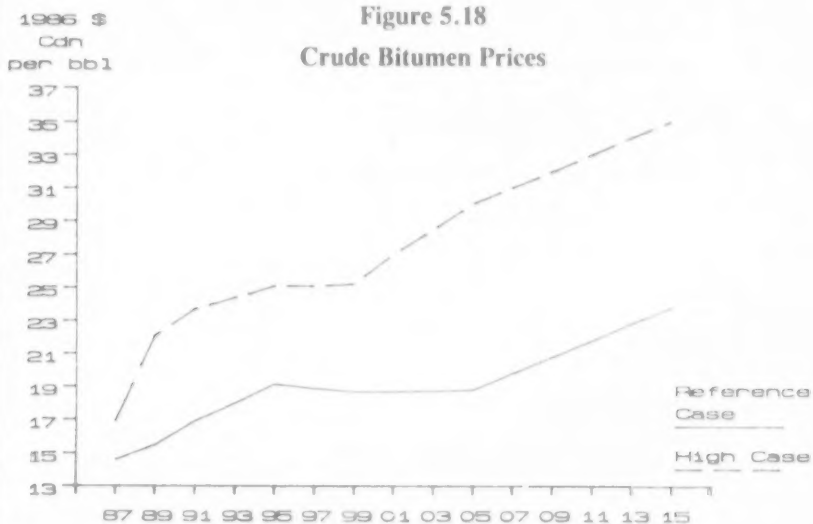
SOURCE: Canadian Energy Research Institute.

Figure 5.17
Synthetic Crude Oil Prices



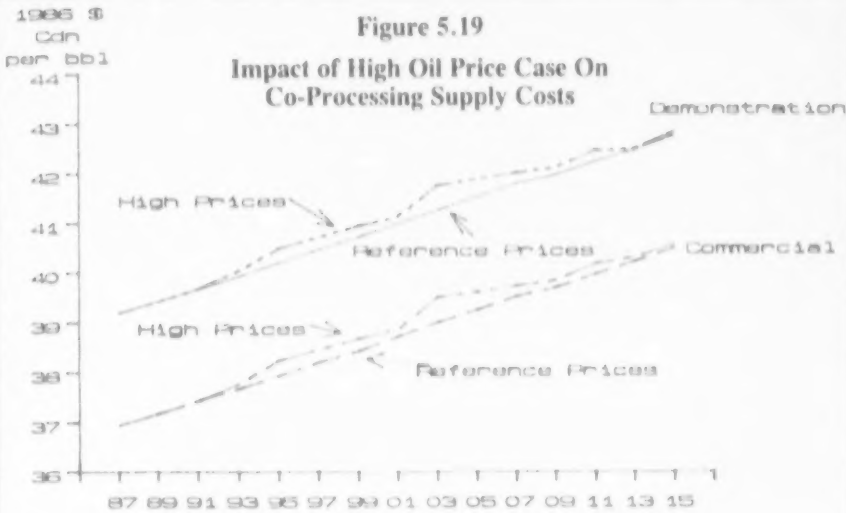
SOURCE: Canadian Energy Research Institute.

Figure 5.18
Crude Bitumen Prices



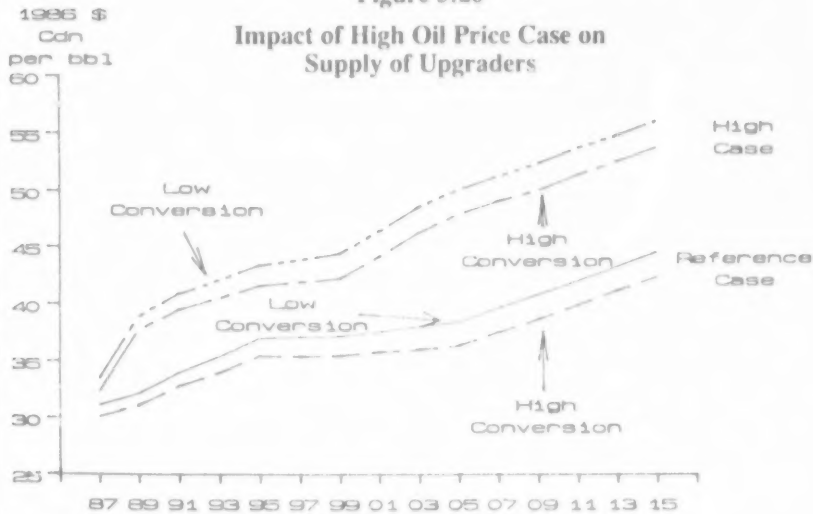
SOURCE: Canadian Energy Research Institute.

Figure 5.19

Impact of High Oil Price Case On
Co-Processing Supply Costs

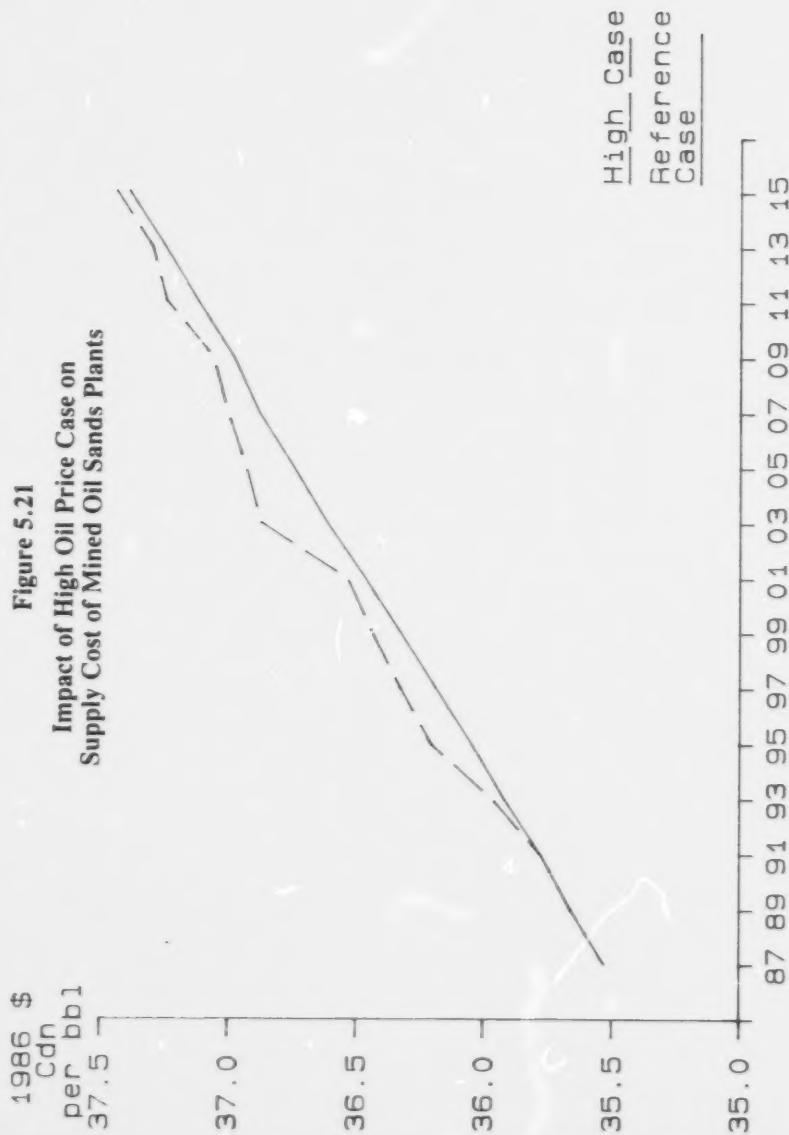
SOURCE: Canadian Energy Research Institute.

Figure 5.20

Impact of High Oil Price Case on
Supply of Upgraders

SOURCE: Canadian Energy Research Institute.

Figure 5.21
Impact of High Oil Price Case on
Supply Cost of Mined Oil Sands Plants



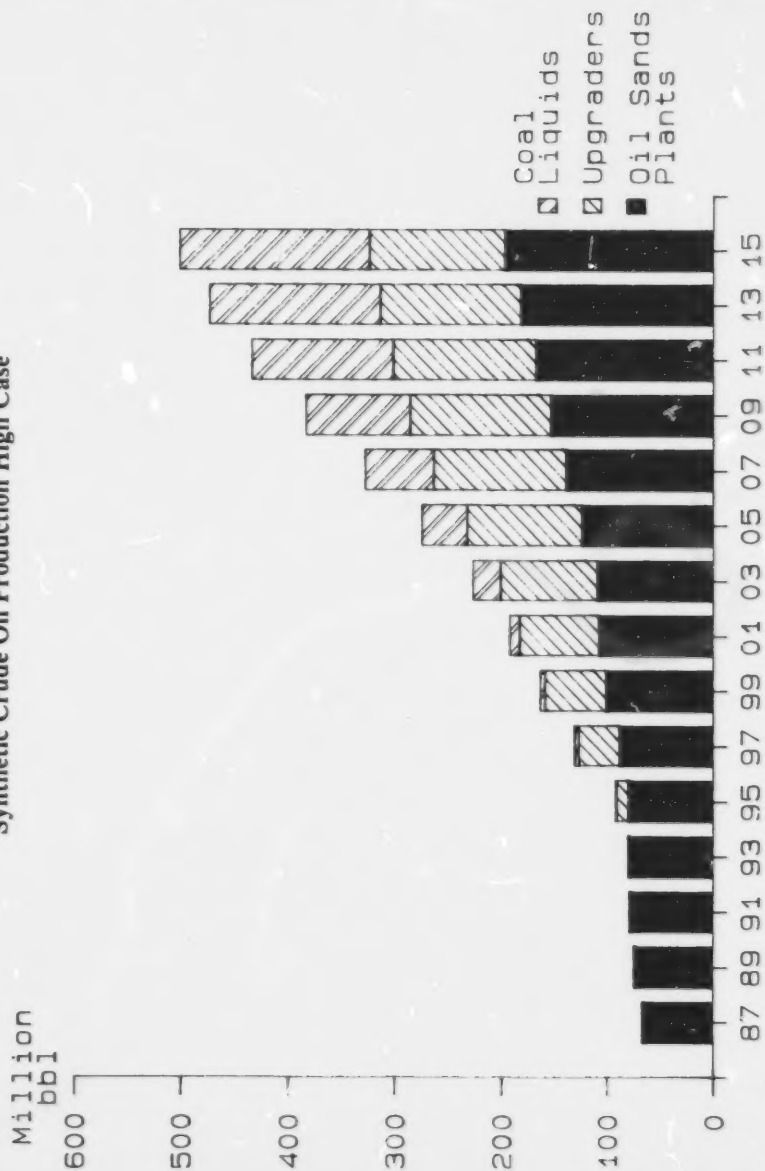
SOURCE: Canadian Energy Research Institute.

TABLE 5.12
HIGH PRICE CASE, SYNTHETIC CRUDE OIL PRODUCTION
(millions of barrels per year)

Year	Integrated Mined Oil Sands Plants		Coal Liquide Production		Upgrader Operations					
	Existing Plants	New Plants	Total	Co-Processing Demonstration	Co-Processing Commercial	Two-Stage Direct	Total	Huakuy-Type		Total MMb/yr.
								Low Conversion	High Conversion	
1987	66-0		66-0							0
1988	74-0		74-0							0
1989	78-0		78-0							0
1990	78-0		78-0							0
1991	78-0		78-0							0
1992	78-0		78-0							0
1993	78-0		78-0							0
1994	78-0		78-0							0
1995	78-0		78-0							0
1996	78-0		78-0							0
1997	78-0	8-7	87-7	4-6			4-6			12-3
1998	78-0	21-2	100-2	4-6			4-6			39-1
1999	78-0	35-3	107-3	4-6			4-6			58-7
2000	78-0	35-3	107-3	4-6			4-6			58-7
2001	72-0	107-3	179-3	4-6	5-4		10-0			75-3
2002	59-0	49-9	108-9	4-6	21-8		28-4			92-5
2003	59-0	64-6	123-6	4-6	38-6		43-2			109-3
2004	59-0	64-6	123-6	4-6	55-4		65-4			126-1
2005	59-0	78-9	137-9	4-6	55-4		65-4			126-1
2006	59-0	83-4	132-4	4-6	55-4	5-4	65-4			126-1
2007	59-0	83-4	132-4	4-6	55-4	5-4	65-4			126-1
2008	59-0	83-4	132-4	4-6	55-4	5-4	65-4			126-1
2009	59-0	83-4	132-4	4-6	55-4	5-4	65-4			126-1
2010	59-0	108-0	167-0	4-6	89-0	21-8	110-8			134-1
2011	59-0	122-5	181-5	4-6	100-4	38-6	139-0			135-3
2012	59-0	122-5	181-5	4-6	100-4	55-4	155-8			133-6
2013	59-0	122-5	181-5	4-6	100-4	55-4	155-8			133-6
2014	59-0	122-5	181-5	4-6	100-4	55-4	155-8			133-6
2015	59-0	137-0	196-0	4-6	100-8	72-2	173-0			129-1

SOURCE: Canadian Energy Research Institute.

Figure 5.22
Synthetic Crude Oil Production High Case



SOURCE: Canadian Energy Research Institute.

compared to only 7 percent under the reference case for primary energy prices. The limited resource potential and high cost of heavy oil feedstock account for the peaking and subsequent decline in production from low conversion heavy oil/bitumen upgraders. While the forecast is illustrative of potential development, it is important to note that Alberta's capability to match the massive employment levels suggested by this forecast is open to question.

5.8 Summary of Findings

Oil price uncertainty has a significant effect on the relative staging of coal-derived synthetic fuels production. A low-price path trajectory results in virtually no new investment in synthetic crude oil capacity additions--low oil prices are insufficient to bring on new production in oil sands plants, upgraders or coal liquids. The net effect of low oil prices is a significant increase in Canadian demand for light crude oil and a marked reliance on imports--which grow to comprise just under 50 percent of Canadian light oil requirements by 2015. A forecast of high energy prices implies substantial growth in all synthetic crude oil options, particularly for coal-derived synthetic fuels which represent a terminal product share value of 35 percent relative to the reference energy price forecast level of 7 percent of total synthetic crude oil production.

The sensitivity cases evaluated in this report all assume that a coal/oil co-processing demonstration (prototype commercial) plant would be in operation and producing in the order of 14,200 b/d of synthetic crude oil by 1997. This assumes that initial feasibility studies and coal-specific research occurs in the next few years. This assumption was predicated on the interest that coal/oil coprocessing has generated as an alternative upgrading process and upon the potential for significant further improvements in process technology and cost reduction. Sufficient interest in the potential of coal/oil co-processing was expected to result in construction of a demonstration plant to prove the economics, operability and conversion of Alberta subbituminous coals by as late as 1997. As presented in this report's reference price case, investment in a commercial coal/oil co-processing plant is economic by 2012, and as early as 1999 under a forecast of higher energy prices.

The lead time potentially available, together with developments currently underway in the United States, should permit deployment of a research capability and infrastructure that would allow Canadians to

evaluate the remaining uncertainties of coal liquids production. This would ensure that appropriate investment decisions are made with the best information possible when required. Identification of the technological uncertainties has largely taken place and it seems an appropriate juncture to evaluate the remaining economic uncertainties and how they might best be resolved so that Canada can unequivocally demonstrate the role of coal-derived synthetic fuels in Canada's future energy mix.

The cases presented in this chapter were not tied to development of the prototype commercial coal/oil demonstration plant in the United States, but assume that Canada embarks on its own evaluation and demonstration program for coal/oil co-processing. In the near-term, this would mean a commitment to a funding level (in the order of \$10-15 million) which would permit a thorough understanding of the conversion properties of Canadian coals, especially inexpensive, low rank Alberta subbituminous coals. Siting studies and initial design work based where applicable on process improvements and prototype demonstration in the United States and other countries might then be undertaken and a demonstration facility built to prove processes and economics for Canadian conditions by as late as 1997.

While the cost of a demonstration facility is a sizeable investment, it is fundamental if we are to fully appreciate the potential role of coal-derived synthetic fuels technology in helping to fill Canada's widening supply-demand gap for light crude oil. If the U.S. prototype demonstration facility proceeds as planned, Canada might forego a significant near-term investment and devote its attention to technical and economic evaluations for specific coals and siting locations. An R & D commitment to evaluation of promising developments in the United States and other countries together with a thorough examination of issues relevant to Canada would pave the way for a state-of-the-art Canadian demonstration plant. A production start-up date of 1997 is believed a realistic time frame for such a development.

While the longer-term costs of a coal/oil co-processing program are potentially significant, the economic benefits of additional coal development together with the increased understanding we would gain of Canada's resource potential could well be of the same order. If international oil prices do rise, as presented in the high price case, investment in coal/oil co-processing would be economic in the latter 1990s and considerable work would have to be undertaken in

the next several years to ensure that Canada would be in a position to build this required capacity using the most appropriate technology.

The most important consideration brought out by the sensitivity analyses presented here is that coal liquids technology, particularly coal/oil co-processing, could potentially be a relatively important Canadian energy supply option. As such, Canada should be actively engaged in addressing the many considerations prerequisite to construction of a demonstration facility. Site-specific feasibility studies are fundamental--coal conversion and pre-treatment, water requirements, environmental and social impacts are a few of the issues that might be addressed in conceptual studies of coal/oil co-processing facilities in Canada.

If demonstration proves the expectations of the two-stage coal/oil co-processing process configuration, project economics could be significantly improved over the relatively conservative figures presented in this study. Importantly, our assessment was also based on using a discount rate of 12 percent for all supply options considered. This in effect assumes that the project risk for all options--reflecting geological risk, process costs, oil prices and social and environmental impacts--are the same for all of Canada's various energy supply options. In fact, they are not equal and the precise figures appropriate to Canada's various supply options would be subject to considerable debate. Reducing the discount rate for coal liquids to account for comparatively lower geological and social risk would act to lower forecast supply costs and advance the initial production date for coal liquids technology and the preparatory work required for its successful implementation.

Footnotes

¹Syncrude Canada Ltd., Application to the Alberta Energy Resources Conservation Board for Expansion of the Syncrude Canada Ltd. Mildred Lake Plant, April 27, 1987.

²Husky Oil Operations Ltd., Bi-provincial Upgrader Project: Environmental Impact Statement, July, 1985.

³P. C. Quinn, R. B. Jeffries, The Bi-Provincial Project Primary Upgrading Technology--Why Ebullated Bed Hydrocracking (H-Oil) Was Chosen, Husky Oil Operations Ltd, UNITAR/UNDP Information Centre for Heavy Crude and Tar Sands, Third International Conference on Heavy Crude and Tar Sands, July 1985.

Chapter 6

CONCLUSIONS

The underlying rationale for this study has been the need to plan for energy contingencies and uncertainty--in particular, uncertainty regarding the future supply of light crude oil in Canada. That Canada's reserves of conventional light crude oil are declining is seldom questioned, but the implications of this for national energy policy and domestic energy development is less certain.

Declining domestic crude oil supply is not, in itself, a rationale for development of non-conventional crude oil reserves and alternative sources of crude oil liquids. In a market-based policy environment, in which domestic oil prices are determined in the world market, source of supply need not be a consideration in energy policy, and domestic resource development should proceed only when it is economic and efficient to do so. Crude oil imports should be pursued to the extent that they are competitively priced, and to the degree that they represent a secure source of domestic supply.

These statements characterize the current Canadian oil market and the consensus forecast for that market for the next 5 to 10 years. Only two elements of this scenario seem relevant to Canadian energy policy--the opportunity cost of crude oil imports and the uncertainty regarding future oil prices. The first element suggests that the cost to Canada of imported oil may be greater than the market price due to the capital investment, labour income and resulting economic spin-offs which are foregone by the transfer of funds to oil exporting countries. The inference is that Canadians should be prepared to pay some premium for domestic resource development, equal to the incremental economic and security benefits arising from that development. This result is independent of any particular development project and applies equally to all import-competing domestic economic developments.

The second element, uncertainty regarding the level of future oil prices, is an issue of technological development and speed of deployment of that technology. If one could accurately forecast the timing and magnitude of future changes in crude oil prices, an economic argument could be made for prebuilding domestic crude oil capacity so

as to have the production volumes in place when they become economic. In an environment characterized by price uncertainty, resource development is not undertaken until the market price is sufficient to justify that development. In this case, the length of time between the development decision and initiation of production represents foregone revenue which, in the case of crude oil, is accruing to foreign countries. Initiatives in research, development and demonstration of crude oil liquids technologies, if undertaken today, can shorten the lead time required for project deployment and put the Canadian energy industry in a better position to react quickly and positively to future market developments.

Coal liquids technology has made significant advances over the last two decades. From a long-term supply alternative with questionable merit, coal liquids technology has progressed to a stage where it represents a potentially economic and viable supply source for Canada within the mid- to latter-1990s. Coal/oil co-processing, the simultaneous conversion of crude bitumen and coal, is a technology which is of particular near-term merit. Unlike tar sands mining/processing plants, bitumen upgrading and frontier resource development, coal/oil co-processing is economic on a relatively small scale, can be sited adjacent to existing infrastructure and, hence, can be geographically distributed so as to minimize the economic boom/bust and dislocation effects associated with megaproject development. In addition, coal/oil co-processing technology utilizes two abundant western Canadian resources, crude bitumen and coal, which require access to new markets in order to justify further development. Production of crude oil liquids represents a potentially enormous market.

Development of a prototype commercial coal/oil co-processing plant in the United States affords Canada a unique opportunity to gain important information on the progress of this technology. The improvements made at this U.S. demonstration plant might conceivably, with appropriate modification, be transferred to Canada for applications in Alberta and in Eastern Canada where security of supply issues are paramount.

The development of a commercial coal/oil co-processing plant in the United States also provides Canada with a window of opportunity to explore technical and economic issues of importance to a site-specific assessment for a Canadian demonstration facility. Conceptual plant

design, siting, coal conversion and coal pre-treatment studies, and social and environmental impact assessments are among the issues that could be addressed in advance of physical construction of a coal/oil co-processing facility. The funding program developed by the U.S. Department of Energy under its Clean Coal Technology Program is an interesting prototype for a joint sponsorship agreement between Canadian industry and government for assessment of a first-of-a-kind Canadian coal/oil co-processing demonstration plant.

If low oil prices do in fact prevail, these preparatory R & D initiatives would end up costing little. If high oil prices take effect, however, R & D expenditures would result in improved investment and policy decisions for all of Canada's energy options. The key source of benefits underlying a move to development and demonstration of coal-derived synthetic fuels stems from improved capabilities to build better and more plants should events force aggressive synthetic fuels development in the future. Practical experience with coal liquids technology will clarify many issues which remain uncertain at this time and this experience will help put this technology into proper perspective for Canada's energy future. Initial production experience will serve, therefore, as insurance which will allow later developments to achieve greater efficiency and lower cost.

Improved information will allow the private sector to better assess alternatives and to undertake investment decisions that are more cost-effective and expeditious. Special attention to improving information on Canada's energy options is particularly important, given the large size of many investments, the substantial uncertainties regarding relative cost and performance, and the demonstrated potential for rapid rates of change in energy markets. Moreover, better information should foster improved national energy policies and encourage cost-effective investment of public resources to address perceived energy problems. Importantly, improved information will also assist in ranking public policy options and focussing timely attention on critical public policy concerns.

A decision to proceed with a pioneer demonstration plant during the next 10 years must be based largely on strategic policy considerations. Because of its complex technical nature and capital intensity, decisions to have in place the capability to produce coal liquid fuels must be taken well in advance of their physical requirement. This course of action is particularly difficult in the current economic climate, and the situation is exacerbated by perceptions of secure and

inexpensive oil supplies for many years to come. However, as R,D&D is by definition an activity with a medium to long-term time horizon, it is important to look beyond current market conditions in assessing the potential benefits of such activity. The evaluation of coal liquids technology presented in this study indicates that coal/oil co-processing is a technology which deserves particular recognition and directed R & D commitment.

In summary, coal liquids technology stands on the verge of being a technically feasible and economically viable Canadian energy supply option in the mid- to latter-1990s. Canada has much to gain from a commitment to a moderately-sized R & D coal/oil co-processing program which examines relevant technical issues and which emphasizes site-specific feasibility studies which employ the most efficient and practical technology.

On the basis of the analysis contained herein, it is strongly recommended that the Canadian government and the governments of the major coal-producing regions of Canada combine to facilitate the examination of all relevant issues prerequisite to the eventual construction of a Canadian coal/oil co-processing facility. Given the uncertainties, a co-sponsored government-industry initiative would seem to represent the best possible combination of risk exposure and Canadian expertise in such an undertaking.

APPENDIX A**UNITS AND CONVERSION FACTORS**



Appendix A

UNITS AND CONVERSION FACTORS

Units

<u>Prefix</u>	<u>Multiple</u>	<u>Symbol</u>
kilo-	10^3	k
mega-	10^6	M
giga-	10^9	G
tera-	10^{12}	T
peta-	10^{15}	P
exa-	10^{18}	E

Btu = British thermal unit

Bcf = Billion cubic feet

Tcf = Trillion cubic feet

\$C = Canadian dollars

\$US = United States dollars

GJ	gigajoule	=	10^9 Joules
TJ	terajoule	=	10^{12} J
PJ	petajoule	=	10^{15} J
EJ	exajoule	=	10^{18} J
kW	kilowatt	=	10^3 watts
kW.h	kilowatt hour	=	10^3 W.h
MW	megawatt	=	10^3 kW
MW.h	megawatt hour	=	10^3 kW.h
GW	gigawatt	=	10^6 kW
GW.h	gigawatt hour	=	10^6 kW.h
TW	terawatt	=	10^9 kW
TW.h	terawatt hour	=	10^9 kW.h

Conversion Factors

Metric	Imperial Equivalent Units
1 cubic metre of oil (15°C and 922 kg/m ³) (15°C and 855 kg/m ³) (15°C and 739 kg/m ³)	= 6.292 26 barrels (60°F and 22°API) = 6.292 58 barrels (60°F and 34°API) = 6.294 03 barrels (equilibrium pressure, 60°F and 60°API)
1 cubic metre of natural gas (101.325 kilopascals and 15°C)	= 35.301 01 cubic feet (14.73 psia and 60°F)
1 cubic metre of ethane (equilibrium pressure and 15°C)	= 6.330 barrels of ethane (equilibrium pressure and 60°F) = 9.930 thousand cubic feet of ethane gas (14.73 psia and 60°F)
1 cubic metre of propane (equilibrium pressure and 15°C)	= 6.300 barrels of propane (equilibrium pressure and 60°F)
1 cubic metre of butanes (equilibrium pressure and 15°C)	= 6.296 8 barrels of butanes (equilibrium pressure and 60°F)
1 tonne	= 1.102 311 tons
1 kilojoule	= 0.948 213 3 British thermal units (Btu)
1 gigajoule (GJ)	= approximately 0.95 million Btu, or 0.95 thousand cubic feet of natural gas at 1000 Btu/cf
1 petajoule (PJ)	= approximately 0.95 billion cubic feet of natural gas, or 165 000 barrels of oil, or 0.28 terawatt hours of electricity.

Gross Energy Content Factors

Ethane (liquid)	18.36 GJ/m ³	
Propane (liquid)		25.53 GJ/m ³
Butanes (liquid)		28.62 GJ/m ³
Crude Oil		
Light and Medium		38.51 GJ/m ³
Heavy		40.90 GJ/m ³
Pentanes Plus		35.17 GJ/m ³
Coal		
Bituminous		29.30 GJ/tonne
Subbituminous		19.76 GJ/tonne
Lignite		15.35 GJ/tonne
Average Domestic Use		24.00 GJ/tonne
Petroleum Products		
Aviation Gasoline		33.52 GJ/m ³
Motor Gasoline		34.66 GJ/m ³
Petrochemical		
Feedstocks		35.17 GJ/m ³
Naphtha Specialties		35.17 GJ/m ³
Aviation Turbo		35.93 GJ/m ³
Kerosene		38.68 GJ/m ³
Diesel		38.68 GJ/m ³
Light Fuel Oil		38.68 GJ/m ³
Lubes and Greases		39.16 GJ/m ³
Heavy Fuel Oil		41.73 GJ/m ³
Still Gas		44.46 GJ/m ³
Asphalt		44.46 GJ/m ³
Petroleum Coke		42.38 GJ/m ³
Other Products		39.82 GJ/m ³

SOURCE: National Energy Board, Canadian Energy Supply and Demand 1985-2005 (Ottawa: Supply and Services Canada, 1986), pp. 128-130.



APPENDIX B
GLOSSARY OF TERMS



Appendix B

GLOSSARY OF TERMS¹

BIOMASS: Organic material such as wood, crop waste, municipal solid waste and mill waste, processed for energy production.

BITUMEN: Viscous mixture of hydrocarbons, which occurs naturally but is not commercially recoverable by standard methods. Also hydrocarbon residue from distillation of some crude oils.

CATALYST: A substance that helps to initiate a chemical reaction and enables it to proceed under less severe conditions (for example, at a lower temperature or pressure), but remains unchanged itself.

CETANE: Liquid hydrocarbon ($C_{16}H_{34}$) used as a reference fuel for diesel engines because of its excellent ignition characteristics.

CETANE NUMBER: A measure of the ignition quality of a diesel fuel when tested in a standard engine against a mixture of n-cetane (cetane number 100) and alphas-methyl naphthalene (cetane number 0). The higher the cetane number, the shorter the delay before ignition. Present diesel engines require fuel with a cetane number of at least 40.

COAL BENEFICIATION: Reduction of ash, moisture and oxygen prior to liquefaction.

COAL DEASHING: Removal of ash and unreacted coal from primary liquefaction products.

COAL GASIFICATION: The production of a synthetic natural gas from coal.

COAL LIQUEFACTION: The production of a synthetic crude oil or related liquid fuel from coal.

¹Excerpts from National Energy Board, Canadian Energy Supply and Demand 1985-2005; House of Commons Standing Committee on Energy Mines and Resources, Oil Scarcity or Security, October 1987, and Energy, Mines and Resources Canada, Future Transportation Fuels: Synthetic Fuels (Ottawa: Supply and Services Canada, 1987).

- COKE:** Solid carbon residue of coal or crude oil that remains after volatile hydrocarbons have been removed by distillation or cracking. Can be used as a feedstock for the manufacture of synthesis gas.
- CONDENSATE:** A mixture mainly of pentanes and heavier hydrocarbons that is recoverable at a well from an underground reservoir, and which is gaseous in its reservoir state but which condenses to a liquid at atmospheric pressure and temperature. Condensate is often included with "crude oil."
- CONTINUOUS STEAM DRIVE:** Enhanced oil recovery (EOR) technique similar to steam injection recovery, but employing more than one production well.
- CONVENTIONAL AREAS:** Generally, the Western Provinces, Southwestern Ontario, and the southern part of the Yukon and Northwest Territories.
- (CONVENTIONAL) CRUDE OIL:** A mixture mainly of pentanes and heavier hydrocarbons that is recoverable at a well from an underground reservoir, and which is liquid at atmospheric pressure and temperature.
- CORROSION:** Erosion of a metal surface caused by chemical reaction of the metal with substances in contact with it.
- CRUDE BITUMEN:** Very heavy crude oil or tar consisting of a naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentane, that may contain sulphur compounds and other minerals, and that in its natural viscous state is not recoverable at a commercial rate through a well.
- CRUDE OIL AND EQUIVALENT HYDROCARBONS:** Sometimes referred to as Crude Oil and Equivalent. Includes light and heavy crude oil, pentanes plus, bitumen and synthetic crude oil.
- CYCLIC STEAM INJECTION:** Steam injection recovery technique in which steam is injected into bitumen-containing formations and heated bitumen, water and gas are pumped out through the same borehole.
- DIESEL FUEL:** High-grade fuel oil suitable for use in compression ignition engines. Available in different grades; regular grade has a cetane number of 40-45 and premium grade of 45-50.
- DIRECT LIQUEFACTION:** Process of obtaining liquid fuel from coal. Hydrogen is added to the feedstock, which is dispersed in a slurry of coal-derived oil.
- DISTILLATION:** Process of heating a liquid to the boiling point and collecting and condensing the resulting vapour.

EMULSION: A milky mixture of two liquids, one forming fine droplets dispersed within the other.

EXPERIMENTAL CRUDE OIL: Crude oil produced from pilot projects designed to investigate new recovery techniques.

FEEDSTOCK: Raw material supplied to a refinery or petrochemical plant.

FIELD: May refer to a certain geographical area from which petroleum is produced or to a particular underground producing zone. A field may contain one or more pools linked by some common element, such as lying along the same trend or being a product of a common geographical disturbance.

FOSSIL FUELS: Combustible geologic deposits of biogenic hydrocarbons. These deposits include crude oil, natural gas, oil shales, oil sands and coal.

FRACTION: Product of refining or distillation consisting of all the compounds which boil between any two arbitrarily chosen temperatures or cut points. Examples are naphtha, kerosene, and fuel oils.

FRACTIONAL DISTILLATION: Product of separating a mixture of liquids of different volatility, e.g., crude oil, into its various components by applying heat and then condensing each vapour as it is collected.

FRACTIONATION COLUMN: Vertical apparatus used for separating gases or liquids into fractions according to their boiling points.

FRONTIER AREAS: Generally, the northern and offshore areas of Canada.

FUEL EFFICIENCY (BURNER TIP EFFICIENCY): The ratio of the useful output energy which results when a fuel is burned, to the theoretical input energy content of the fuel. Fuel efficiency for a heating fuel is less than 100 percent to the extent that heated air is used in combustion and to the extent that exhaust venting is necessary. In other applications, fuel efficiencies are less than 100 percent partly because of waste heat generation.

GAS OIL: Heavy refinery fraction (boiling point between 232°C and 426°C) used in industry and as a fuel for diesel engines.

GASIFICATION: Production of methane from coal or biomass by heating the feedstock to high temperatures under high pressure in a restricted amount of oxygen.

GASOLINE: Refined mixture of volatile, petroleum-derived hydrocarbon liquids with octane numbers ranging from 60 to above 100; used as a fuel for spark ignition engines.

HEAVY CRUDE OIL: Crude oil with high viscosity and high boiling point, recoverable only to a limited extent by standard techniques.

HEAVY FUEL OIL: Heavy fuel oil includes bunker fuel oils (No. 5 and No. 6 fuel oils) and industrial fuel oil (No. 4 fuel oil). Oil from deposits intermediate between oil sands and conventional crude oil. Flows very slowly or not at all under normal conditions.

HYDROCARBONS: Any organic compounds--solid, liquid or gaseous--consisting only of the elements carbon and hydrogen. Crude oil, natural gas and coal are essentially mixtures of hydrocarbons of varying degrees of complexity and containing varying amounts of impurities such as sulphur, nitrogen, oxygen, helium and metallic elements.

HYDROCRACKING: Refining process for splitting heavy hydrocarbons into lighter fractions by adding extra hydrogen under high pressure with the aid of an acid catalyst.

HYDROGEN: The simplest and lightest element. In its molecular form it is a colourless, odourless, tasteless gas, but it never occurs naturally in this form.

HYDROLIQUEFACTION: Production of liquid fuels from coal by direct liquefaction involving the addition of extra hydrogen.

HYDROTREATING: Refinery process in which hydrogen is added to remove impurities like sulphur and metals from the product stream.

INDIRECT LIQUEFACTION: Production of liquid fuels from coal via an intermediate process of gasification.

IN-SITU RECOVERY: The process of recovering crude bitumen from oil sands other than by surface mining.

KEROGEN: Fossilized, insoluble organic material found in sedimentary rocks, usually shales, which can be converted by distillation into petroleum products. Kerogen is considered to be a precursor of petroleum.

LIGHT CRUDE OIL: A term applied to crude oil having a low density and which yields relatively high proportions of gasoline, naptha and kerosene fractions.

LIGHT FUEL OIL: The term light fuel refers to furnace fuel oil (No. 2 fuel oil), kerosene and stove oil (No. 1 fuel oil). The major volume of light fuel oil used in Canada is furnace fuel oil.

LIQUEFIED PETROLEUM GASES (LPG): A subgroup of the natural gas liquids, consisting principally of propane and butanes, obtained from crude oil and natural gas production and also as by products of refining. Compressed to liquid form for storage and transportation and used as a fuel.

M-GASOLINE: Patented term for synthetic gasoline manufactured from methanol using a process developed by Mobil Oil Company.

MARKETABLE NATURAL GAS: Raw gas from which natural gas liquids and nonhydrocarbon gases have been removed or partially removed by processing. Marketable gas is also known as "pipeline quality gas" or "sales gas," and is composed primarily of methane.

MEDIUM CRUDE OIL: Crude oil intermediate in viscosity between heavy and light crude oil.

METHANE: Colourless, odourless, flammable gas with the formula CH_4 , making it the simplest hydrocarbon. Main constituent of natural gas.

METHANOL: Colourless, toxic liquid with the formula CH_3OH ; the simplest of the alcohol series. Also called methyl alcohol.

MIDDLE DISTILLATES: The range of refined petroleum products which includes kerosene, stove oil, diesel fuel, and light fuel oil.

NAPHTHA: Petroleum fraction with boiling range of 70°C to 200°C . Octane number is too low for direct use as gasoline. A primary feedstock for the production of petrochemicals.

NATURAL GAS: Flammable mixture of gaseous hydrocarbons, mainly methane. Occurs naturally, usually in association with crude oil.

NATURAL GAS LIQUIDS (NGL): The hydrocarbons ethane, propane, butane, and pentanes plus or a combination thereof.

OCTANE NUMBER: An arbitrary value that indicates the anti-knock quality, or grade, of a gasoline, i.e., provides a measure of the resistance of the fuel to premature ignition. The proportion of iso-octane (octane number 100) in the mixture indicates the octane number of the gasoline blend. Available gasoline blends usually range in octane number from 92 to 100.

OIL: A combustible liquid generally considered to have been formed by geochemical processes acting on the remains of organisms buried in the geologic past. Although oil basically consists of only two elements, carbon and hydrogen, it is characterized by an enormously complex variety of molecular structures - no two crude oils from different sources are identical. Despite this almost unlimited complexity, most crude oils contain 84 percent to 87 percent carbon by weight and 11 percent to 14 percent hydrogen.

In addition to carbon and hydrogen, there are small amounts of other elements present, typically in amounts aggregating less than 3 percent by weight of the oil. Sulphur, nitrogen, and

oxygen are the principal "contaminants", although traces of sodium chloride, phosphorus and heavy metals such as vanadium and nickel are common. Heavy oil and natural asphalt may have a sulphur content of 5 percent or more.

The conversion of organic material contained in sediments into petroleum is a function of temperature (in turn related to depth of burial) and time.

Deeper burial by continuing sedimentation, increasing temperatures, and advancing geologic age result in the mature state of petroleum formation during which the full range of petroleum compounds is produced from kerogen and other precursors by thermal degradation and cracking (the process by which heavy hydrocarbon molecules are broken up into lighter molecules). Depending on the amount and type of organic matter, oil generation occurs during the mature stage at depths of about 760 to 4,880 metres (2,500 to 16,000 feet) at temperatures between 65° and 150°C. This special environment is called the "oil window." In areas of higher than normal geothermal gradient (increase in temperature with depth), the oil window exists at shallower depths in younger sediments but is narrower. Maximum oil generation occurs from depths of 2,000 to 2,900 metres. Below 2,900 metres primarily wet gas, a type of gas containing liquid hydrocarbons known as natural gas liquids, is formed.

At the end of the mature stage and at depths greater than about 4,900 metres (16,075 feet), depending on the geothermal gradient, crude oil becomes unstable and the main hydrocarbon product is dry gas (methane). At sediment temperatures greater than about 250°C (482°F), hydrocarbons cease to be generated from organic matter. Depending on its geologic history then, a sedimentary formation may be oil prone, gas prone, both or neither.

Oils are usually characterized by their API gravity, on a scale adopted by the American Petroleum Institute to measure the specific gravity of crude oils. This scale arbitrarily assigns an API gravity of 10° to pure water. Oils lighter than water have an API gravity greater than 10°; those heavier than water have a value less than 10°.

OIL SANDS: Deposits of sand or sandstone, or other sedimentary rocks containing crude bitumen which is too viscous to be recovered through a conventional well.

OIL SHALE: A kerogen-bearing, brown or black shale that will yield gaseous or liquid hydrocarbons on distillation.

PENTANE: Colourless, flammable hydrocarbon liquid derived from petroleum and found in gasoline.

PENTANES PLUS: A mixture mainly of pentanes and heavier hydrocarbons that is obtained from the processing of raw gas, condensate or crude oil.

PERMEABILITY: A measure of the capacity of a reservoir rock to transmit fluids.

PETROLEUM: A Latin derivative literally meaning "rock oil" and often defined as naturally occurring liquid hydrocarbons. Sometimes the definition is extended to include refined products in the liquid state. In common industry usage, petroleum has come to mean any hydrocarbon mixture that can be produced through a drill pipe, including natural gas, condensate and crude oil.

POOL: A natural underground reservoir containing an accumulation of oil and/or natural gas separated, or appearing to be separated, from any other such accumulation.

PROPANE: Heavy, volatile, colourless hydrocarbon gas that can be readily liquefied at ambient temperatures and is the main component of LPG. Can be extracted from natural gas and is also produced during refining.

PYROLYSIS: Chemical change caused by the action of heat without oxidation. Usually causes breakdown of complex molecules into simpler ones, such as the conversion of organic wastes to fuel gases.

RECOVERABLE: That portion of a resource which is expected to be recovered using present techniques and under current economic conditions.

REFINING: Process of heating crude oil until it separates into its chemical components, which are then processed into useable products.

REMAINING ESTABLISHED RESERVES: Initial established reserves less cumulative production.

RESERVES: That portion of the resource that has been discovered, of which part is recoverable under current economic and technical circumstances and part is not.

RESERVES ADDITIONS: Incremental changes to established reserves resulting from the discovery of new pools and reserves appreciation.

RESERVES APPRECIATION: Incremental change in established reserves resulting from extensions to existing pools and/or revisions to previous reserves estimates.

RESERVES LIFE INDEX: Remaining reserves divided by annual production.

RESERVOIR: A porous, permeable sedimentary rock containing commercial quantities of oil and/or natural gas.

RESOURCE: All oil and gas accumulations either known or inferred to exist. That portion of the resource base which has been found is referred to as discovered resources or reserves. That portion of the resource which is inferred to exist but not yet discovered is known as undiscovered resources or potential resources.

SHALE OIL: Oil obtained from the treatment of kerogen contained in oil shale. No shale oil is produced in Canada at the present time, although oil shales are found in various regions of the country.

SOCIAL SUPPLY COST: The sum of capital and operating costs per unit of production, exclusive of royalties, taxes, subsidies, or incentive payments, discounted at the estimated social opportunity cost of capital in Canada.

STEAM INJECTION RECOVERY: In-situ technique involving injection of high-pressure steam to recover heavy oil and oil sands bitumen; may be cyclic (using one borehole) or continuous (using separate injection and production wells).

STEAM REFORMING: Production of synthesis gas by passing methane or other hydrocarbon vapour over a catalyst at a high temperature.

SURFACTANT: Liquid added to an emulsion to ensure that the liquids do not separate out.

SYNTHETIC FUELS: Liquid or gaseous fuels, similar to those made from light crude oil, produced from bitumen, heavy oil, natural gas, coal or biomass.

SYNTHETIC CRUDE OIL (Syncrude): As commonly understood in Canada, a mixture mainly of pentanes and heavier hydrocarbons that is derived from crude bitumen through the addition of hydrogen or the deletion of carbon, and which is liquid at atmospheric pressure and temperature. Syncrude also includes oil obtained from oil shale or coal.

SYNTHETIC NATURAL GAS (SNG): Natural gas produced from petroleum liquids, coal or wood.

TAR SANDS: Sands impregnated with a heavy crude oil, tar-like in consistency, that is too viscous to permit recovery by natural flowage into wells. This term used to be applied to the bitumen deposits of Alberta but has largely been supplanted by "oil sands" in Canadian usage. In the United States and elsewhere, the term "tar sands" is still in common use.

THERMAL PROCESSES: Enhanced oil recovery processes in which heat is added to the reservoir to increase recovery.

TOWN GAS: Fuel gas with a high hydrogen content manufactured from coal and used for lighting, heating and cooking prior to widespread use of natural gas.

UPGRADING: Conversion of bitumen or heavy oil into synthetic crude oil.

VISCOSITY: Measure of a liquid's resistance to flow at a specified temperature. A higher viscosity measure indicates a lower flow rate under a given set of conditions.

VOLATILE: Readily evaporates at relatively low temperatures.

WOOD GASIFICATION: The production of a synthetic natural gas from wood.

WOOD LIQUEFACTION: The production of liquids (e.g., methanol) from wood.

WOOD WASTE: Fuel consisting of bark, shavings, sawdust and low grade lumber and lumber rejects from the operation of pulp mills, sawmills and plywood mills.

APPENDIX C

RESEARCH AND DEVELOPMENT - OVERVIEW



Appendix C

RESEARCH AND DEVELOPMENT - OVERVIEW

The information presented in the following pages is meant to serve as a brief overview of the nature of research, development, and demonstration programs on coal liquefaction which have been undertaken in various countries. While it is representative of activities, the substantial reductions in R & D funding precipitated by the recent fall in oil prices may make some of the information presented here somewhat dated.

C.1 Japan

Coal liquefaction research and development in Japan was commenced in the 1920s when the basic research phase was conducted. During the 1930s techniques were commercialized so that during the 1940s, Japanese-designed and run plants were in commercial scale operation in South Manchuria using subbituminous coal, and in Korea using brown coal. Both these plants were based on the Bergius 1911 process using a feedstock of powdered coal mixed with oil and catalyst, pressure-cooked together at about 200 atmospheres and a temperature of 400 degrees celsius. The plant in China produced 12 tonnes per day of oil and the one in Korea produced oil at the rate of 270 tonnes per day, of which 150 tonnes per day was gasoline. In the 1950s, research and development on coal liquefaction was resumed in Japan, only to be dropped in the 1960s for a period of ten years, due to the "era of cheap oil."¹

Almost immediately after the 1973 "oil shock," Japan revitalized her program with the aim of producing liquids from coal on a commercial basis by about the year 2000.

On October 1, 1980, the Japanese Government established the New Energy Development Organization (NEDO) which is presently active in new energy technology development, development of geothermal resources and overseas coal, rationalization of the domestic coal industry and production of alcohol for industrial use. Synthetic fuel activity is aimed mainly at coal gasification and liquefaction. The goal of the Japanese program is to develop liquefaction technologies to the

demonstration stage so that full-scale plants can be built when the world price of oil is in the range of \$35-40 (U.S.) per barrel.²

Japan's major project is the 50 tonne per day (dry) brown coal liquefaction plant being constructed in Australia. NEDO is also promoting a bituminous coal liquefaction pilot plant project for black coal liquefaction in Japan, and design studies have already begun. The process is an integration of three coal liquefaction methods and has some characteristics which are similar to other processes developed in Europe and the United States. The NEDO process claims more than a 50 percent conversion of coal to light and middle distillates under relatively mild conditions of temperature and pressure and can utilize a variety of coals. Coals from the U.S.A., Japan, China, Australia and Canada will be tested in the pilot plant when it begins operation in 1990.³

C.2 U.S.A.

In response to the Iran oil cut-off, skyrocketing oil import prices and their inflationary impact on the American economy, and continuing unrest in the Middle East, the Carter Administration formulated a definitive national synthetic fuels policy. The plan called for reducing the country's dependence on imported oil by 50 percent by 1990. The Energy Security Act of 1980 established the Synthetic Fuels Corporation (SFC) and empowered it to undertake massive investments to develop synthetic fuels and to act as a catalyst for private investment in a domestic synthetic fuel industry.

The Energy Security Act authorized the SFC to provide financial assistance to qualified projects (\$88 billion was authorized to promote initial synfuel development) which would produce synthetic liquids, solids or gases from coal, including lignite and peat, oil shale, tar sands and heavy oil. Through the competitive award of price guarantees, loan guarantees, purchase agreements and direct loans, the SFC was expected to offset the substantial financial risks associated with constructing and operating first-of-a-kind commercial size plants. Budgetary pressures, a new administration skeptical of the merits of a major federal role in energy markets, and the prospects of weaker oil prices resulted in the signing of legislation on December 19, 1985 which rescinded the remaining SFC spending authority and phased out the SFC over the following 3-month period.

While a number of projects received active attention by private and government sponsors in the mid and latter 1970s, interest in direct coal liquefaction has steadily decreased during the 1980s. It has declined to the point that there is now only one integrated coal liquefaction plant operating full-time in the United States, that being the 6 ton-per-day facility in Wilsonville, Alabama. Major concerns regarding future funding and operations for continued R & D at Wilsonville persist.

Development of HRI's H-Coal process culminated in the construction and operation of a 250 ton-per-day pilot plant in Cattlesburg, Kentucky. This plant operated successfully under U.S. Department of Energy and Industrial sponsorship from early 1980 to late 1982.

The Exxon Donor Solvent process was successfully tested in a 250 ton-per-day pilot plant at Baytown, Texas from 1980-1982 under a government/industry co-operative program.

The original Wilsonville plant, which began operations in 1974, was a single-stage dissolution of coal followed by a solid-liquid separation to give upgraded fuel for boilers. The facility gradually evolved into a highly versatile plant which is presently configured with two closely-coupled ebullated-bed reactors in series. This facility remains the last active, full-time, fully-integrated direct liquefaction facility in the U.S. and has become the focus of technology development as it is the only place to test new concepts in an integrated plant. Most of the funding today for Wilsonville comes from the U.S. Department of Energy. The Electric Power Research Institute (EPRI) has provided most of the capital and owns the facility. Southern Company Services, Stearns-Catalytic and Amoco are responsible for various operating and technical aspects of the plant and also contribute private sector funding to the project.

In a recent technical brief, EPRI summarized the U.S. direct liquefaction situation as follows:

The Exxon Donor Solvent Process and H-Coal processes are now ready for commercial application ... large scale utility site tests on the liquid products were carried out by Consolidated Edison and Mississippi Power in boilers, Philadelphia Electric in a gas turbine and by Easton (Maryland) Utilities in a diesel engine. These test programs clearly demonstrated that these liquids could be used as substitute fuels with satisfactory results ... A new integrated two-reactor system

has demonstrated distillate product yield improvements that surpass H-Coal and EDS by about 25 percent. Thermal efficiency of a coal-to-fuel complex of 70 percent and liquid product of 4 barrels per ton of coal can be achieved.⁴

C.3 Australia

The Australian National Energy Research Development and Demonstration Program is funding research into direct liquefaction, indirect liquefaction, and pyrolysis as a way of more fully utilizing Australia's abundant coal resources. Feasibility studies have been funded by the federal government and the governments of the States of Queensland, New South Wales and Victoria. Foreign companies from Japan, the Federal Republic of Germany and the United States have participated in the Australian research effort.

The brown-coal liquefaction pilot plant in Victoria State is the most significant synfuels activity in Australia. The project is based on two-stage liquefaction technology developed in Japan by the Nippon Brown Coal Liquefaction Co. Ltd. (NBCL). The pilot plant is being constructed and will be operated by a wholly-owned subsidiary of NBCL which is a consortium of five Japanese companies. Stage 1 has been commissioned; Stage 2 was scheduled for completion in 1987; and operations for the integrated pilot plant are expected in 1989. The project is a cooperative venture between the Japanese and Australian federal and Victoria state governments and is being financed entirely by the Japanese government through its New Energy Development Organization.⁵

C.4 Federal Republic of Germany (FRG)

German scientists pioneered the work in both direct and indirect liquefaction technologies in the early part of this century. Between the late 1920s and the end of World War II, a large synthetic fuels industry fueled transport and Germany's war effort. The upgrading of coal has always been given a prominent position in German research and development, as coal is the only primary source of energy which is available in large quantities from domestic reserves, but is expensive to mine. Advanced technologies are being investigated to obtain cleaner, easier to handle and favourably priced products from coal. These developments are being financed through joint efforts by German industry and public funds. Liquefaction of coal is a main topic

for research in the field of upgrading with public and private participation in both local and U.S. projects.

In many respects, coal liquefaction remains a central but longer-term component of the German Energy Research Program. The long-term emphasis stems from the understanding that very sophisticated technology requires long periods for development and considerable funds.⁶ Secondly, economic utilization of coal liquefaction in the FRG is only to be expected in the distant future due to high (and subsidized) coal prices. The incentive for development nevertheless continues as German improvements in technology could be applied earlier in countries where coal prices are less costly.

After the Second World War, the indirect, Fischer-Tropsch synthesis process was operated to a limited extent to produce fuels until the early 1960s when it was shut down due to pressure from inexpensive Middle East oil. While some limited work continued on improving the Fischer-Tropsch process, public support for R & D ceased as it was reasoned that commercial-scale use in South Africa would continue to support improvements in process technology. Primary interest in liquids could not continue to support the Fischer-Tropsch process as it was recognized that this process could not compete with direct liquefaction of coals that were high in volatile matter and comparatively low in ash content.

In January 1980, the FRG Government decided on a large-scale program for the promotion of coal gasification and liquefaction technologies. The program provided for the accelerated development of major technical installations which were to become operational in 1984.⁷

Three coal liquefaction pilot plants were established:

- 200 tonne a day pilot plant in Bottrop, developed by Ruhrkohle AG and Veba Oel AG which started operations in 1981 to test variations in reaction parameters, different catalysts and partial processing stages and their influence on overall conversion efficiencies;
- 6 tonne per day pilot plant in Fuerstenhausen, developed by Saarbergwerke AG; and
- 3 tonne per day pilot plant in Lahr, developed by Salzgitter AG and Imhausen Chemie GmbH.

All pilot plants received significant financial support (75 percent to 80 percent) from the state and FRG Government.

C.5 United Kingdom

Two liquefaction routes were recently under study by the National Coal Board through its Coal Research Establishment at Stoke Orchard. Liquid fuel production as well as the the production of chemicals from coal were considered beneficial. The technologies being evaluated are Liquid Solvent Extraction and Supercritical Gas Solvent Extraction. Information gained from the experimental units at Stoke Orchard led to a decision to build a pilot plant for each technology at Point-of-Ayr in Wales. Each is to have a capacity of 25 tonnes/day of coal.⁸

C.6 Canada

Coal conversion research and development in Canada has encompassed all approaches: gasification, pyrolysis and liquefaction. Early work consisted of technical and economic evaluations of known technologies. Canadian coals were sent for testing of their coal conversion properties at R & D centers in the United States, West Germany, the United Kingdom and Japan. In the past decade, Canadian R & D facilities have been established to undertake hands-on research into the conversion properties of domestic coals. These research centers have proven valuable contributors to the understanding of coal conversion technology and have made significant advances in areas of considerable importance to the exploitation of Canadian coals for liquid fuels (see Table C.1).

The Canada Centre for Mineral and Energy Technology (CANMET), a branch of Energy, Mines, and Resources Canada, has provided direct and partial support for a variety of projects. In addition to contracting out and cost-sharing programs, CANMET also conducts an in-house research and development program on various topics of interest, including the hydrocracking processes for upgrading heavy oils; synthesis of methanol, gasoline and diesel fuels; distillate upgrading; and the co-processing of coal with bitumen or heavy oil. The eventual need to replace the present less efficient carbon rejection process of upgrading bitumen by hydroprocessing (or hydrogen addition) has also encouraged considerable work on the development of CANMET's hydrocracking technology. "The process uses an inexpensive coal-based additive to suppress coke formation. At present the coal represents only 5 percent

TABLE C.1

LIQUEFACTION PROPERTIES OF MAJOR CANADIAN COAL FIELDS (representing 85% of Canada's measured and indicated coal reserves)

Region	Alberta		British Columbia		N.E.		Alberta		Saskatchewan		Nova Scotia	
	Plains	Haccreek	S.E. Coal Fields	L, M, Volatile Bituminous	L, M, H-Volatile Bituminous	Coal Fields	Plains	Lignite	Cape Breton			
<u>Coal Characteristics</u>												
Rank	Subbituminous	Subbituminous	L, M, Volatile Bituminous	L, M, H-Volatile Bituminous	Subbituminous	Coal Fields	Plains	Lignite <td>Cape Breton<td colspan="2">High Volatile Bituminous</td></td>	Cape Breton <td colspan="2">High Volatile Bituminous</td>	High Volatile Bituminous		
Typical ash (% dry)	9.5	35	>10	>10	>10		11-21	20		4-15		
Mineable Coal (megatonnes)		839	-	-	-		7 328	2 150		370		
Measured and Indicated (megatonnes)		1 936	15 722	1 456	30 000		47.12	6.62		12		
X Canadian Total Measured and Indicated Reserves												
<u>Liquefaction Testing</u>												
Test Facility	Canmet	S.C. Research	S.C. Research	S.C. Research	Alberta Research Council	Sandwell Research Centre	10 kg/h Bench Liquefaction Unit	2 kg/h Bench Liquefaction Unit	Once-through, Recycle	Non-Catalytic Hydrogenation	Catalytic- Hydrogenation	
Test Unit	1 kg/hr Con- tinuous Unit	Continuous Autoclave	Tubing Bomb Autoclave	Tubing Bomb Autoclave	Batch	Batch	Batch	Batch	Batch	Batch	Batch	
Operating Mode	Co-processing once through	Recycle	Batch	Batch	Batch	Batch	Batch	Batch	Batch	Batch	Batch	

TABLE C.1 (cont'd)

Region	Alberta		British Columbia		Alberta		Saskatchewan	Nova Scotia	
	Plains	Mountain	S.E. Coal Fields	N.E. Coal Fields	Plains	Lignite	Lignite	Cape Breton	
<u>Test Conditions</u>									
Solvent Used	Bitumen/ Residue	Recycle	Various	Various Bitumen	Anthracene Oil & Bitumen & Heavy Oil	Lignite Derived	Recycle		
Gas Used	Hydrogen	Hydrogen	Hydrogen	Hydrogen	Hydrogen, CO, Steam	Hydrogen	Hydrogen		
Catalyst	Proprietary	None	Various	Various	Dispersed Mo, Carbonate	None	Co, Ni, Mo		
Residence Time (hr)	Proprietary	.5			.5	1.01	0.5		
Temperature (°C)	Proprietary	440			380-470	440	450-465		
Pressure (MPa)	Proprietary	15.1			10.4	24.2	17.4		
<u>Typical Results</u>					(Range of 5 coals)				
Overall Conversion (% H ₂)	85-90	>90	50-93	50-90	87-96	90-95	90		
Gross Liquid Yield (C ₄ +)	70		35-60	35-75	50-70	60-67	68-73		
Hydrocarbon Gas Yield (% H ₂)	6.0	6.5-6.8	3-5	2-5	5-10	5-6	12-17		
H ₂ O, CO, CO ₂ Produced	-	12	10-12	10-12	10-20	22-25	3-5		
<u>Comments</u>									
General Comments	Excellent Hydrogen Con- sumption	Difficult to Liquefy	Difficult to Liquefy	Difficult to Liquefy	Good-excellent Conversion	Good-excel- lent Conver- sion	Good Lique- faction Feed- stock		
Special Technical Requirements		Beneficiation and Deashing			Beneficiation and Deashing, Efficient Ox- ygen Removal	Beneficiation and Deashing, Efficient Ox- ygen Removal			

of the coal/bitumen mixture, but the aim is to increase this proportion up to 50 percent to achieve what will essentially become a co-processing operation.⁹

The Federal Government's effort in coal conversion processes has been concentrated mainly on extending CANMET's hydrocracking technology to the co-processing of coal with bitumen, heavy oil or refinery residues acting as solvents or hydrogen donors.

Compared to conventional coal liquefaction processes, co-processing has been shown to produce increased liquid yields and improved product quality. Moreover, hydrogen consumption efficiencies are found to be better than those of the more advanced two-stage coal liquefaction processes now under development.¹⁰

The provinces and the private sector have also embarked on significant research programs for producing oil from coal, particularly in Alberta and Nova Scotia. In the Atlantic region, the Nova Scotia Research Foundation has conducted bench-scale studies on the liquefaction of Cape Breton's high volatile bituminous coals. They are presently primarily involved in the assessment of two-stage direct liquefaction for the production of transportation fuels and believe that coal can eventually support 40 to 50 percent of their long-term transportation requirements. In addition to this work, a private consortium, Scotia Synfuels Limited, completed a technical and economic feasibility study of a two-stage direct liquefaction plant on the premise that the coal reserves of Cape Breton could be transferred into light oil at a cost comparable to Alberta's heavy oils and tar sands. Recent work has centered on the application of two-stage coal/oil co-processing for the upgrading of Cape Breton coals employing the process technology to be used at the Warren, Ohio prototype commercial coal/oil co-processing plant.

At SNC Inc., Montreal, considerable experimental work has been undertaken on coal beneficiation as an integral part of the liquefaction process. This research showed that by using a portion of the heavy recycle oil for beneficiation, a reduction of up to 70 percent of the coal mineral matter can be achieved. Reduction of oxygen content in the coal prior to its conversion was also investigated by using inorganic reducing agents.¹¹

Sandwell Technologies in Toronto has been involved in Canadian low rank coal experimentation for over a decade with some assistance

from cost-sharing programs with CANMET. Results obtained on work with Saskatchewan lignite have shown that these coals are highly reactive and can be liquefied without the use of a liquefaction catalyst. In addition, a rather novel product recovery/solids separation process was developed which decreases the cost of coal-derived liquids by 25 to 30 percent depending on coal feed properties.

Through the Alberta/Canada Energy Resources Research Fund, the Province of Alberta continues to provide substantial support for the Alberta Research Council's coal liquefaction research activities, which are concentrated on evaluating the reactivity of Alberta subbituminous coal under hydroliquefaction and pyrolysis process conditions. In addition, financial support has been provided to the Canadian Coal Liquefaction Corporation for a study of the feasibility of liquefaction of Alberta subbituminous coal. The selected process is intended to embody the most recent developments in coal liquefaction and co-processing technologies with application to high oxygen content subbituminous coals which are typical of those found in Western Canada.¹²

Canadian Energy Developments Inc. (formerly the Canadian Coal Liquefaction Corporation), with support from the Alberta Government's Office of Coal Research and Technology, established a project with the primary objective of confirming the technical and economic viability of co-processing Alberta heavy oil and subbituminous coal.

In the last 3 years, Canadian Energy Developments Inc. (CED) has created a data base by successfully completing experimental work in:

- 2 Kg/hr. Bench Scale Hydrogenation Unit;
- 0.8 to 1.3 litre Lab Scale Hydrocoker; and
- 30 ml Microautoclave Screening unit.

In the fiscal year 1987-1988, CED constructed and commissioned a fully automated pilot plant of 1/4 t/d capacity, in co-processing mode.

CED has acquired a great deal of insight into co-processing technology and the following two process configurations have been established:

(1) The CCLC Process

This is a two stage process consisting of:

- (i) First Stage - Solvolysis
- (ii) Second Stage - Hydrogenation

Coal is solubilized into heavy oil in the First Stage under mild severity. All the product from the First Stage is then subjected to Second Stage hydrogenation (at moderate severity). This two-stage process is a very efficient way of transferring hydrogen via heavy oil to coal with the formation of distillable oil yield.

(2) The PYROSOL Process

This is also a two stage process:

- (i) First Stage - Mild Hydrogenation
- (ii) Second Stage - Hydrocoking

In the First Stage a maximum amount of coal is solubilized into the heavy oil with the production of a small quantity of lighter product (less than 10 wt%). The lighter product is distilled off at the hot separator and the hot separator bottom is then subjected to Second Stage hydrocoking.

The concept of hydrocoking is quite specific for the PYROSOL Process, where coking is carried out under pressurized hydrogen. The advantage of the process is that it produces about 70 wt% distillable oil, with hydrogen consumption less than 1 wt% of dry-ash-free feed.

CED has also completed a preliminary feasibility study to determine the economic merits of the co-processing alternative relative to direct heavy oil upgrading and has examined how co-processing can best fit within an existing refinery infrastructure. Kilborn Limited of Toronto was retained in the evaluation of the technical and economic potential of the integration of a coal/heavy oil coprocessing unit within an existing refinery. The results indicate a discounted cash-flow rate of return to equity in excess of 14 percent. The plant was assumed to begin operations in 1992 and produce 20,900 b/d of syncrude quality crude comparable to that presently produced by Suncor and Syncrude. A financial analysis was also undertaken for the economics of an upgrader for the same vacuum residual feedstock without coal addition, using the best available technology. This caused the rate of return on equity to fall to just over 6 percent, illustrating the economic importance of adding lower cost coal to the feed.¹³

CED expects pilot plant demonstration runs and feasibility studies to be completed by the end of 1990 and commissioning of a co-processing plant by 1993-994.

In British Columbia, B.C. Research has conducted extensive experimentation on the liquefaction potential of B.C.'s low and medium volatile bituminous coal and B.C. Hydro has undertaken a technical and economic evaluation of the liquefaction of Hat Creek subbituminous coal.¹⁴

In February 1987, the Ontario Ministry of Energy joined with a private firm, Ontario-Ohio Synfuels (OOS), in a 1-year feasibility study of a prototype coal/oil co-processing plant in Ontario. The study's objective is to evaluate the construction and operation of a demonstration plant in the Sarnia area to produce some 12,500 barrels per day of light synthetic crude oil from a mixture of Ohio coal and either tar sands bitumen from Alberta or heavy refinery residues. The process technology would be based on new, proprietary American coal/oil coprocessing technology from Hydrocarbon Research Inc. The feasibility study is currently underway, with final results expected in the fall of 1988.

C.7 Conclusions

Research on the conversion of coal to fuels and chemicals has probably been more intensive in Germany than in any other country. Coal conversion provided the basis for Germany's chemical industry and the fuels for much of Germany's war efforts. The availability of cheap petroleum from the Middle East reduced Germany's needs for coal products and caused the shut-down of many of its coal-based chemical operations, though limited research and German participation in liquefaction R & D in other countries has continued.

The oil crisis of 1973-1974 sponsored a sharp increase in coal conversion R & D in many countries. Considerable experimental work, pilot-plant designs and construction were undertaken in many countries in the expectation that full-scale conversion plants would be required in the latter 1980s. Work was especially active in West Germany and the U.S.A., and to a lesser extent in the U.K., Japan, Australia and Canada.

The amount of research which has been undertaken in Canada on coal liquefaction has been extremely modest relative to that of other countries. Canada's synfuel research and demonstration program has been dominated by activities relating to the recovery and upgrading of heavy oils and oil sands. This in part reflects the fact that the urgency for obtaining oil and gas from coal has not been considered as great in Canada as in other countries because of Canadian perceptions of the availability of conventional oil and gas supplies and the availability of non-conventional oil sands, heavy oil and frontier supply sources. It may in part also stem from the fact that resources for research and development are not as great in Canada as in several other countries. It seems likely that when the need for building coal conversion plants becomes apparent, much of the required technology will have been developed and tested in other countries and Canada might import it. However, because of the differences in conversion characteristics between coals, the conversion of Canadian coals will require potentially significant "adoptive" research and demonstration programs to address the unique features of Canadian coals.

There are significant differences in the reactivity of coals from various regions across Canada and often also within the same coal deposit. Consequently, reliable performance data for specific deposits can only be derived from extensive testing of a sufficient number of representative samples from that deposit. Economics of coal conversion are highly dependent on yields of liquid products which in turn are highly sensitive to process conditions and coal characteristics ... The prospects for improving economics through process optimization and research are excellent ... The high reactivity shown by some coals (e.g., certain Alberta subbituminous coals and Saskatchewan lignites), even under mild conditions, lends further support for continued R & D on small scale process development units to aid selection of processes for scale up.¹⁵

Notwithstanding the late start in obtaining the necessary research facilities, Canada has made considerable progress. Valuable information has been obtained on Canadian coals and their performance in different conversion processes and promising process adaptations and innovations have been identified and are under development. Canadian coals have generally exhibited the potential for good conversion and almost 60 percent of Canada's measured and indicated coal reserves are potentially suitable for liquefaction, with the application of appropriate technology.¹⁶ It appears that a concentrated effort to further understand the properties of these coals is warranted so as to

develop the most appropriate and efficient processes for their conversion into liquid fuels.

Despite the work that has gone on in the past, lack of a definitive policy on coal liquids technology together with the fall in oil prices and government and private sector budget cuts has meant that a sizeable component of Canada's R & D initiative has been brought to a standstill. While many of the questions have been answered in the laboratory, the economic factors have now become more pronounced, placing the onus of proof on a demonstration plant which would further optimize the conversion properties of coal and give a definitive understanding of the future commercial viability of coal-liquids processes for Canada.

Footnotes

¹Joseph MacDowall, "An Overview of Japanese Coal Liquefaction Within the Sunshine Project," in Proceedings of The Coal Liquefaction Contractor's Review Meeting (Ottawa: November 8-9, 1982), p. 304.

²Some additional detail on Japan's coal liquefaction program is presented in "Present Status of Coal Liquefaction In Japan" by Shinichi Satake in Proceedings of the Coal Liquefaction Contractor's Review Meeting (Calgary: November 14-16, 1984).

³Australia Department of Resources and Energy, Energy 2000: A National Energy Policy Review-Synfuels, Energy 2000 Policy Review Discussion Paper Number 7 (Canberra: Department of Resources and Energy, 1986), p. 17.

⁴Electric Power Research Institute Advanced Power Systems Division. Technical Brief: Direct Liquefaction of Coal (Palo Alto, California: EPRI, 1986), p. 2.

⁵Australia Department of Resources and Energy, op. cit., p. 17.

⁶W. Bertram, H. J. Neef, and J. J. Stocker, "Coal Liquefaction In the Federal Republic of Germany," in Proceedings of the Coal Liquefaction Contractors' Review Meeting (Calgary, Alberta: November 14-16, 1984), p. 121.

⁷Australia, Department of Resources and Energy, op. cit., p. 21.

⁸S. S. Patel and T. D. Pay "Foreign Coal Liquefaction Technology Survey and Assessment," in Symposium Papers, Advances in Coal Utilization Technology IV (Denver, Colorado: April 20-24, 1981), p. 122.

⁹International Energy Agency, Synthetic Liquid Fuels: An IEA Seminar, OECD (Paris, 1985), p. 66.

¹⁰Ibid. p. 67.

Note also "CANMET Co-processing: A Status Report" by J. F. Kelly, S. A. Fouda, P. Rahimi, and M. Ikura, Seminar Paper 21 in Proceedings of Coal Conversion Contractors' Review Meeting (Calgary: November 14-16, 1984),

¹¹National Coal Conversion Committee, Position Paper on Coal Liquefaction in Canada, prepared for Energy, Mines and Resources Canada, DSS Contract No. 03GR.23218-3-0014, April 1985, pp. 4-7.

¹²International Energy Agency, Synthetic Liquid Fuels: An IEA Seminar, op. cit., p. 67.

¹³Personal correspondence from Dr. E. St. Denis, Manager Research and Development, CCLC Technologies, Inc., (formerly Canadian Coal Liquefaction Corporation), August 13, 1987 and Dr. D. K. Banerjee, Project Scientist, Canadian Energy Developments Inc., April 11, 1988.

¹⁴See Coal Liquefaction Steering Committee Report to the Energy Development Agency, Hat Creek Coal Liquefaction Project: Steering Committee Report, June 1981.

¹⁵C. W. Bowman and M. P. du Plessis. "The Canadian Synthetic Fuel Industry--A Major User of Hydrogen," in International Journal of Hydrogen Energy, vol. II, no. 1 (Great Britain: Pergamon Press Ltd., 1986), p. 50.

¹⁶Canadian Coal Conversion Committee, op. cit., pp. 5-6.

APPENDIX D

THE U.S. COAL/OIL CO-PROCESSING PROGRAM



Appendix D

THE U.S. COAL/OIL CO-PROCESSING PROGRAM

D.1 The U.S. Coal/Oil Co-Processing Program

The information presented below summarizes the steps which led to further development of Hydrocarbon Research Inc.'s (HRI) coal/oil co-processing process and which culminated in a U.S. Department of Energy award for construction of a Prototype Commercial Coal/Oil Co-Processing Plant in Ohio.

In April 1985, HRI initiated a private-industry sponsored research and development program on its coal/oil co-processing process. To a large degree the program was based on proving the potential application of HRI's CTSL direct liquefaction process to the two-stage catalytic co-processing of heavy crudes and coal.

Phase I of the program was sponsored by:

- Electric Power Research Institute (EPRI)
- Ontario-Ohio Synthetic Fuels Corporation, Ltd. (OOSFC)
- Alberta Research Council
- Dynalectron Corporation

The State of Ohio's Coal Development Office also supported Phase I of the program through OOSFC. The objective of the program was to further develop, demonstrate, and optimize HRI's Ebullated-Bed Coal/Oil Co-Processing technology to produce high quality, environmentally acceptable products from poor quality feedstocks.

Phase I was completed in April, 1986 and a summary presentation of program findings was presented at EPRI's Eleventh Annual Conference on Clean Liquid and Solid Fuels in May, 1986.¹ In addition, a complete description of the findings of the Phase I program including detailed capital and operating cost assumptions was presented under separate cover in a report published by EPRI in March, 1987.²

The Phase I technical tasks included feedstock characterizations of four coal and four oil feedstocks, batch reactivity screening,

continuous bench unit operations, product characterizations, economic screening studies and commercial planning studies.

Based on the successful completion of Phase I, a subsidiary of OOSFC, Ohio-Ontario Clean Fuels, Inc. (OOCF) teamed up with HRI and Stears Catalytic Corporation to submit a Clean Coal Technology Proposal to the United States Department of Energy (DOE) and the Ohio Coal Development Office for support of a prototype commercial coal/oil co-processing plant. Of 51 proposals submitted to DOE, the prototype commercial coal/oil co-processing plant proposal was one of the 9 selected to enter into contract negotiations with DOE under the Clean Coal Technology Program.³

D.2 Phase I Program Description

In December 1985, Congress made funds available for a Clean Coal Technology (CCT) Program in Public Law No. 99-190. This Act provides funds for the purpose of conducting cost-shared Clean Coal Technology projects for the construction and operation of facilities to demonstrate the feasibility of future commercial applications. The Act authorized DOE to conduct the CCT program and also directed DOE to prepare a full and comprehensive report to Congress of any project to receive an award under the CCT program. In October 1987 DOE, in fulfillment of this directive, submitted a comprehensive description of OOCF's Prototype Commercial Coal/Oil Co-processing plant to Congress. "The total estimated cost of the project is \$225,674,805 of which \$45,000,000 will be funded by DOE and \$180,674,805 has been assembled by OOCF from other sources, including \$9,700,000 from the State of Ohio."⁴

The program was divided into two parts. The objective of the Phase I program was to demonstrate the feasibility of the HRI Ebullated-Bed Coal/Oil Co-processing technology. A follow-on Phase 2 program was to expand the data base to other coal/oil pairs and develop conceptual commercial plant design and economics.

Under the Phase I program, coals and petroleum residues of near-term commercial interest for co-processing in North America were evaluated. The feedstocks selected represented a wide range of physical properties, chemical properties and processing characteristics. The feedstocks noted below were analyzed and tested at several levels under the program. Technical tests included:

- feedstock characterization,
- reactivity screening,
 - microautoclave testing
 - autoclave testing
- continuous bench unit operation,
- commercial planning,
- product characterization,
- economic screening studies.

The feedstocks evaluated were:

Coals

1. Eastern, Appalachian Bituminous Coal (Ohio No. 5/6)
2. Low Sulphur, Subbituminous Coal (Alberta)
3. High Sulphur Bituminous Coal (Illinois No. 6)
4. U.S. Gulf Coast Lignite (Martin Lake, Texas)

Oils

1. High Metals Residuum (Mexican Maya)
2. Western Canadian Heavy Feedstock (Cold Lake Residuum)
3. U.S. Gulf Coast Residuum (West Texas Sour)
4. Great Lakes Residuum (Interprovincial Pipeline)

The coal analyses performed included proximate, ultimate, petrographic and mineral analyses. For the oils, elemental analysis as well as physical and chemical characterizations were performed. Table D.1 summarizes some of the feedstock characterizations and shows that of the coals tested, Ohio No. 5/6 coal and Illinois No. 6 coal are similar. The Ohio coal has a lower ash content and higher hydrogen content. The Alberta subbituminous coal is similar to typical Wyoming subbituminous coals.⁵

Two process variable bench runs were completed in the Phase I Program. Both runs used the Ohio No. 5/6 coal and Cold Lake atmospheric residuum. The first run was done using a single-stage process configuration to:

TABLE D.1
FEEDSTOCK ANALYSES

<u>Coals</u>	<u>Ohio No. 5/6</u>	<u>Illinois No. 6</u>	<u>Alberta Subbituminous</u>	<u>Texas Lignite</u>
Carbon, W %	75.3	69.9	67.9	63.3
Hydrogen, W %	5.6	4.9	4.7	5.3
Nitrogen, W %	1.6	1.4	1.4	1.2
Sulphur, W %	3.0	3.7	0.5	1.2
Ash, W %	6.8	11.7	8.2	12.0
Oxygen, W % (by difference)	7.7	7.8	17.3	17.0
H/C Atomic Ratio	0.89	0.84	0.83	1.00
<u>Oils</u>	<u>Cold Lake</u>	<u>IPL</u>	<u>Maya</u>	<u>West Texas Sour</u>
*API	6.9	14.5	4.1	14.7
W % 975°F+	70	68	85	65
Hydrogen, W %	10.1	10.8	9.7	11.5
Nitrogen, W %	0.5	0.4	0.7	0.3
Sulphur, W %	5.2	1.3	5.0	2.4
Nickel and Vanadium, Wppm	330	44	637	62
RCR, W %	18.4	12.3	24.1	8.3
Oils, W %	39	55	30	58
Resins, W %	41	36	39	38
Asphaltenes, W %	20	9	31	4

SOURCE: "HRI's Coal/Oil Co-processing Program - Phase I" by J. E. Duddy, J. B. MacArthur and J. B. McLean, Presented to EPRI's Eleventh Annual Conference on Clean Liquid and Solid Fuels (Palo Alto, California: May 7-9, 1985), p. 13.

- provide baseline data for evaluation of major process variables and comparison to subsequent two-stage operations;
- gain experience in co-processing the selected feedstocks so that potential operating problems could be better anticipated for two-stage testing; and
- allow direct comparison with HRI's H-Oil Process data base on the selected oil feedstock over a similar range of operating conditions.

The second bench runs were conducted using a two-stage process configuration. Conditions were selected based on single-stage results to:

- obtain high liquids conversion, in the range of 90 W % M.A.F., such that the bottoms from vacuum distillation would contain approximately 50 W % solids; and
- obtain a high quality vacuum gas oil product which would be suitable for use as a low sulphur fuel oil or a high quality turbine fuel.

Table D.2 summarizes yield and process performance for three conditions from Bench Run No. 1, the single-stage process configuration. Operating conditions were identical for each set shown except for the coal concentration in the fresh feed and recycle rate required.

Table D.3 summarizes similar data for two conditions from Bench Run No. 2, the two-stage process configuration. Table D.4 compares product quality data from the two runs which indicates the superior process performance and product quality obtained from the two-stage process configuration.

D.3 Program Results

The continuous bench unit operations demonstrated the technical feasibility of the HRI Ebullated-Bed Coal/Oil Co-processing technology over a wide range of operating conditions and conversions, in both single- and two-stage process configurations. Operations ran quite smoothly, with no evidence of feedstock or product incompatibility causing operating problems. High liquid conversions were obtained in the two-stage operations with excellent selectivity to liquid products and superior product quality (see Figure D.1).

TABLE D.2
CONTINUOUS BENCH UNIT OPERATIONS
(bench run No. 1 - single-stage)

Feedstocks: Cold Lake Atmospheric Residuum
 Ohio No. 5/6 Coal

	5	2	4
<u>Condition</u>			
W % Coal in Fresh Feed	33	50	67
<u>Yields, W %</u>			
<u>Dry Coal Plus Oil</u>			
C ₁ -C ₃	6.0	5.0	5.3
C ₄ -390°F	14.4	14.5	11.2
390-650°F	25.1	24.7	22.5
650-975°F	24.7	25.7	24.9
975°F+	17.8	17.0	21.4
Unconverted Coal	2.8	3.2	3.7
Ash	2.4	3.5	4.6
H ₂ O, CO _x , NH ₃ , H ₂ S	9.4	9.5	9.6
Total	102.6	103.3	103.3
<u>Process Performance, W % M.A.F.</u>			
975°F+ Conversion	74	75	70
Coal Conversion	91	93	94
Hydrodesulphurization	79	83	70
Hydrodenitrogenation	50	64	54
Demetallization	92	95	92
<u>C₄-975°F</u>			
W % M.A.F.	66	67	61
B/T Total Feed	4.4	4.4	3.9
B/B Oil Feed	1.2	1.5	2.0

SOURCE: "HRI's Coal/Oil Co-processing Program - Phase I" by J. E. Duddy, J. B. MacArthur and J. B. McLean, Presented to EPRI's Eleventh Annual Conference on Clean Liquid and Solid Fuels (Palo Alto, California: May 7-9, 1985), p. 20.

TABLE D.3
CONTINUOUS BENCH UNIT OPERATIONS
(bench run no. 1 - two-stage)

Feedstocks: Cold Lake Atmospheric Residuum
 Ohio No. 5/6 Coal

	6	4
<u>Condition</u>		
W % Coal in Fresh Feed	33	50
<u>Yields, W %</u>		
<u>Dry Coal Plus Oil</u>		
C ₁ -C ₃	8.0	6.2
C ₄ -390°	21.4	17.6
390-650°F	36.4	34.1
650-975°F	19.7	23.2
975°F+	4.5	6.7
Unconverted Coal	1.4	2.0
Ash	2.4	3.6
H ₂ O, CO _x , NH ₃ , H ₂ S	9.5	10.8
Total	103.3	104.2
<u>Process Performance, W % M.A.F.</u>		
975°F+ Conversion	92	90
Coal Conversion	95	96
Hydrosulphurization	91	86
Hydrodenitrogenation	78	80
Demetallization	99	99
<u>C₄-975°F</u>		
W % M.A.F.	79	78
B/T Total Feed	5.4	5.1
B/B Oil Feed	1.4	1.8

SOURCE: "HRI's Coal/Oil Co-processing Program - Phase I" by J. E. Duddy, J. B. MacArthur and J. B. McLean, Presented to EPRI's Eleventh Annual Conference on Clean Liquid and Solid Fuels (Palo Alto, California: May 7-9, 1985), p. 21.

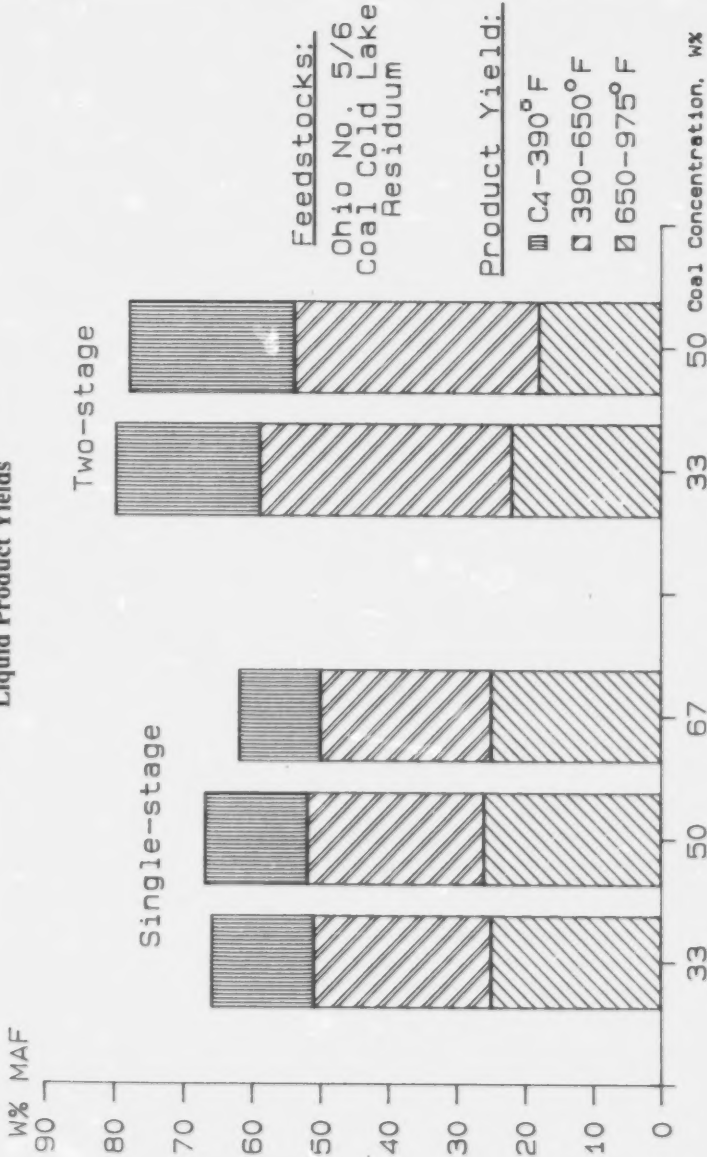
TABLE D.4
CONTINUOUS BENCH UNIT OPERATIONS

Feedstocks: Cold Lake Atmospheric Residuum
Ohio No. 5/6 Coal

	Single Stage			Two Stage	
	6	2	4	6	4
<u>Condition</u>					
W % Coal in Fresh Feed	33	50	67	33	50
<u>Liquid Product Quality</u>					
<u>Naphtha, IBP -390°F</u>					
Gravity, °API	53.1	50.8	46.3	54.2	53.0
Hydrogen, W %	13.47	13.60	13.00	13.85	13.86
Sulphur, W %	0.10	0.08	0.11	0.04	0.02
Nitrogen, W %	0.14	0.07	0.15	0.15	0.06
<u>Distillate, 390-650°F</u>					
Gravity, °API	28.3	28.9	25.8	30.5	28.7
Hydrogen, W %	11.77	12.02	11.46	12.13	11.76
Sulphur, W %	0.42	0.11	0.22	0.06	0.04
Nitrogen, W %	0.18	0.17	0.30	0.17	0.22
<u>Vacuum Gas Oil, 650-975°F</u>					
Gravity, °API	13.0	15.4	10.7	15.1	13.3
Hydrogen, W %	10.39	10.65	9.69	10.72	10.54
Sulphur, W %	0.90	0.34	0.43	0.22	0.17
Nitrogen, W %	0.41	0.36	0.48	0.36	0.35

SOURCE: "HRI's Coal/Oil Co-processing Program - Phase I" by J. E. Duddy, J. B. MacArthur and J. B. McLean, Presented to EPRI's Eleventh Annual Conference on Clean Liquid and Solid Fuels, (Palo Alto, California: May 7-9, 1985, p. 22.

Figure D.1
Continuous Bench Unit Operations
Liquid Product Yields



SOURCE: Hydrocarbon Research Inc., HRI's Coal/Oil Co-Processing Program Phase 1, May 7 - 9, 1986, p26.

The major conclusions stemming from the Phase I program were:

- Product Characterization - the products from coal/oil co-processing will fit well into existing liquid fuel markets. (See Table D.5 per coal/oil co-processing products, their probable disposition and possible further upgrading required).

The coal/oil co-processing naphtha contains higher concentrations of naphthenes and aromatics compared to a H-Oil Process naphtha derived from processing Cold Lake atmospheric residuum. The resulting product from catalytic reforming will have a higher octane number, with higher volumetric yield, at lower operating severity.

The mid-distillate and vacuum gas oil products from coal/oil co-processing are extremely low in sulphur and considerably lower in nitrogen compared to products from direct coal liquefaction. These products could be combined and used as a low sulphur fuel oil or turbine fuel for utility application, without further upgrading (see Table D.6).

- Process Synergy - operations completed in Phase I showed process synergy in at least two areas. First, the conversion to distillate products by co-processing is greater than would be expected from conversions obtained by separate processing of the coal and oil feedstocks. Second, continuous bench unit operations have also shown that a significant amount of metals removal occurs on the coal solids.
- Process Performance - excellent process performance was obtained. Liquid yields in excess of 5.4 barrels/ton of total feed were obtained in two-stage bench unit operations and as high as 4.4 barrels/ton in single-stage bench unit runs.

The two-stage process configuration is technically preferred to achieve high liquids conversion and product quality.

- Economics - Economic screening studies were undertaken to evaluate the effect of process variables on relative economics and to provide guidance with respect to selection of process conditions for subsequent bench runs in the program.

These studies were based on the single-stage process configuration and assumed that the coal/oil co-processing plant was an add-on to an existing petroleum refinery. The co-processing facilities included coal preparation (storage, crushing, and drying), co-processing, hydrogen production, product upgrading, product treating and offsets/utility tie-ins. It was assumed that petroleum residuum was available from the refinery and that the refinery would accept the coal/oil co-processing products after appropriate upgrading. A summary of the cases evaluated

TABLE D.5
PRODUCT CHARACTERIZATION
OVERVIEW OF CO-PROCESSING PRODUCTS

Co-Processing Product	Nominal Boiling Range	Probable Disposition	Possible Further Upgrading
Naphtha	18P-390°F	Gasoline	Hydrotreating and Catalytic Reforming
Mid-Distillates	390-500°F 500-650°F	Jet Fuel Diesel Fuel No. 2 Fuel Oil Turbine Fuels No. 6 Fuel Oil	Hydrotreating
Vacuum Gas Oils	650-850°F 850-975°F	Conversion No. 6 Fuel Oil Turbine Fuels Recycle to Reactor	Hydrotreating Fluid Catalytic Cracking Hydrocracking
Resid (Excluding Solids)	975°F+	No. 6 Fuel Oil Recycle to Reactor	Flaking, Fluid Coking
Resid (Including Solids)	975°F+	Partial Oxidation Direct Combustion Solids Separation Recycle to Reactor	

SOURCE: "HRI's Coal/Oil Co-processing Program - Phase I" by J. E. Duddy, J. B. MacArthur and J. B. McLean, Presented to EPRI's Eleventh Annual Conference on Clean Liquid and Solid Fuels (Palo Alto, California: May 7-9, 1985), p. 22.

aIncluding oil-fired combined cycle electric power generation.

TABLE D.6
PRODUCT CHARACTERIZATION

	<u>Mid-distillate</u>		
<u>I Coal Feed</u>	<u>0</u>	<u>33-50</u>	<u>100</u>
*API	32	29	23
Hydrogen, W I	12.5	12.0	11.0
Sulphur, W I	0.7	< 0.1	< 0.1
Nitrogen, W I	0.2	0.2	0.3
Cetane Index	41	36	28
	<u>Vacuum Gas Oil</u>		
*API	19	15	9
Sulphur, W I	1.3	0.2	< 0.1
Nitrogen, W I	0.3	0.35	0.6

TABLE D.7
ECONOMIC SCREENING STUDIES
SUMMARY OF CASES

<u>Case</u>	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>4A</u>	<u>5</u>
Overall Feed Rate, TPSD	-----3000----->					
Percent Coal Feed	33	50	67	33	33	50
975°F+ Conversion, W I	74	75	70	84	84	59
Co-Processing Bottoms Processes	-----Coking----->				POX	Coking
Hydrogen Source	-----Steam Reforming----->				POX	Steam Reforming
Recycle, W I of FF	-	50	115	-	-	50

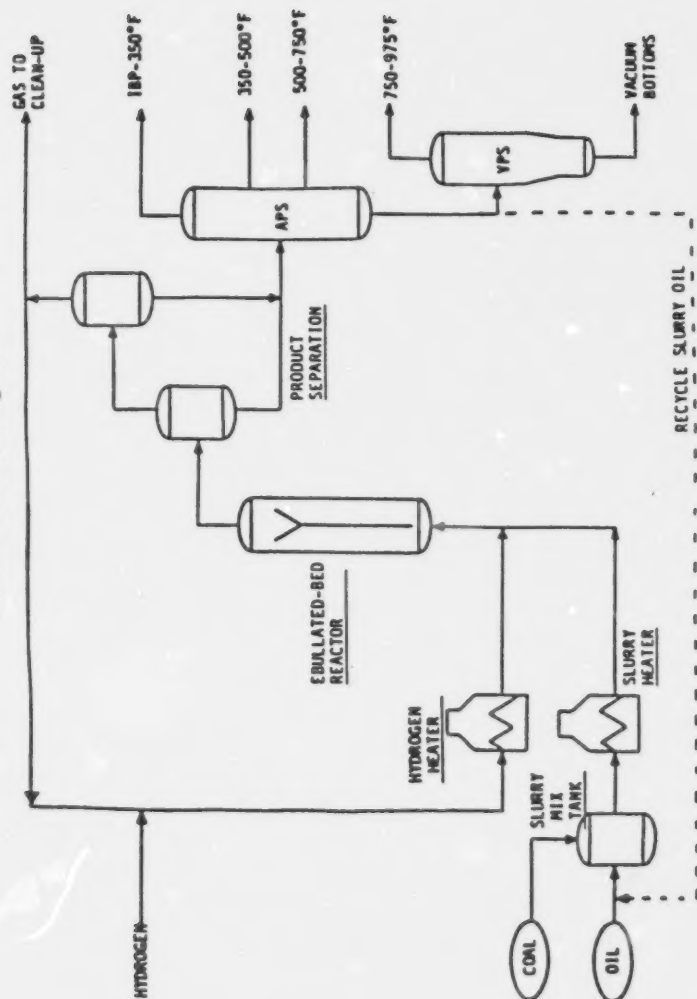
NOTE: POX = Partial Oxidation

TABLE D.8
ECONOMIC SCREENING STUDIES
SUMMARY OF RESULTS

<u>Case</u>	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>4A</u>	<u>5</u>
Percent Coal Feed	33	50	67	33	33	50
Overall Feed Rate, TPSD	-----3000----->					
C4-975°F Product, BPSD	14100	14200	12750	14850	14000	12500
Estimated Investment, MM\$	240	260	300	260	300	249
Operating Cost, MM\$/Yr.	93	89	87	97	93	87
By-Product Revenues, MM\$/Yr.	(5)	(5)	(6)	(5)	(13)	(6)
Net Cost, MM\$/Yr.	88	84	81	92	80	81
First-Year Product Cost, \$/B	23.03	22.24	24.87	22.89	22.39	24.01

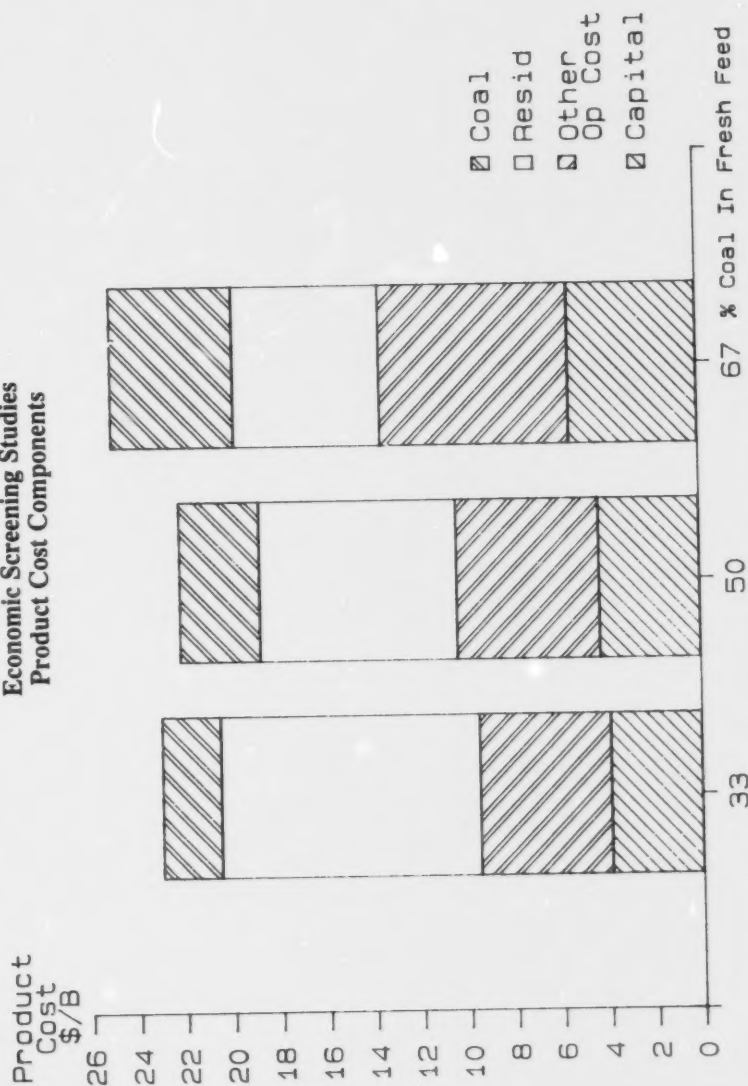
SOURCE: "MRI's Coal/Oil Co-processing Program - Phase I" by J. E. Duddy, J. B. MacArthur and J. B. McLean, presented to EPRI's Eleventh Annual Conference on Clean Liquid and Solid Fuels (Palo Alto, California, May 7-9, 1985), p. 30.

Single-stage Co-processing -
Schematic Flow Diagram



SOURCE: Hydrocarbon Research, Inc., "HRI's Coal/Oil Co-Processing Program - Phase I" by J. E. Duddy, J. B. MacArthur, and J. B. McLean, Paper presented to KRI's Eleventh Annual Conference on Clean Liquid and Solid Fuels (Palo Alto, California, May 7-9, 1986), published in HRI Coal/Oil Co-Processing Technology: Status Report; May, 1987, p. 31.

Figure D.3
Economic Screening Studies
Product Cost Components



SOURCE: Hydrocarbon Research Inc., HRI's Coal/Oil Co-Processing Program Phase 1, May 7 - 9, 1986, p31.

is provided in Table D.7. Figure D.2 presents a simplified flow diagram for commercial single-stage co-processing operations.

In the base Cases 1-5, the bottoms from coal/oil co-processing are coked, and hydrogen is produced via the steam reforming of natural gas. Each case is based upon 3,000 tons-per-day (TPSD) of total coal plus oil feed. In Cases 1-3, the coal concentration increases from 33 to 67 W%, at otherwise constant operating conditions. Case 4 is based on high conversions at 33 W % coal and Case 5 is based on low conversion at 50 W % coal. In Case 4A, the coal/oil co-processing bottoms are used to manufacture hydrogen.⁶

As shown in Table D.8, first-year product costs per barrel for the various cases range from \$22.24 to \$24.01 a barrel. First-year product costs were calculated as the 30-year levelized product costs of discounted operating costs and revenue requirements assuming an annual inflation rate of 8.5 percent and a 12.5 percent weighted cost of capital. Product cost components (capital, other operating, residuum and coal) are shown versus the percent coal in the fresh feed in Figure D.3. As the coal concentration increases, the relative contribution of feedstock decreases as the cost of coal (\$1.25/MMBtu) is considerably less than the cost of residuum (\$15/B or about \$2.5/MMBtu). The cost of capital and other operating expenses (labour, maintenance, natural gas utilities), however, increases with coal concentration. As shown in the figure, 50 percent coal is slightly preferred to 33 percent coal with product costs of about \$22-23/bbl whereas the product cost at 67 percent coal is considerably higher. While HRI's economic screening studies show that the economics of 33 percent and 50 percent coal are similar, generally a ratio of 50 percent coal in the fresh feed is preferred as it is not as sensitive to the price of oil.

On the basis of its analyses, HRI recommended that the future program focus on high conversion operations, and that a 50 percent coal content in the fresh feed is preferred, in respect to both economics and process reactivity.⁷

Footnotes

¹Hydrocarbon Research, Inc., "HRI's Coal/Oil Co-Processing Program - Phase I" by J. E. Duddy, J. B. MacArthur, and J. B. McLean, Paper presented to EPRI's Eleventh Annual Conference on Clean Liquid and Solid Fuels (Palo Alto, California, May 7-9, 1986), published in HRI Coal/Oil Co-Processing Technology: Status Report, May, 1987.

²Electric Power Research Institute, Coal/Oil Co-Processing: Phase I, AP-5101, Research Project 2657-1, Interim Report, prepared by Hydrocarbon Research Inc. for Electric Power Research Institute, Alberta Research Council and Ontario-Ohio Synthetic Fuels Corporation Ltd., March 1987.

³United States Department of Energy, Office of Fossil Energy, Comprehensive Report to Congress Clean Coal Technology Program: Prototype Commercial Coal/Oil Co-Processing Plant, a project proposed by Ohio Ontario Clean Fuels Inc., October, 1987.

⁴Ibid., p. 5.

⁵Hydrocarbon Research Inc., "HRI's Coal/Oil Co-Processing Program" by J. E. Duddy, J. B. MacArthur, and J. B. McLean, Paper presented to the Direct Liquefaction Contractors Review Meeting, Monroeville, Pennsylvania, October 21-22, 1986 published in HRI Coal/Oil Co-Processing Technology: Status Report, May 1987, p. 4.

⁶Hydrocarbon Research Inc., May 7-9, 1986, op. cit., p. 10.

⁷Electric Power Research Institute, op. cit., p. 8-30.

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